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BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

IN RE: ATLANTA GAS LIGHT COMPANY'S)
2004-2005 RATE CASE) DOCKET NO. 18638-U

DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

(Revenue Requirements)

ON BEHALF OF THE

GEORGIA PUBLIC SERVICE COMMISSION ADVERSARY STAFF

FEBRUARY 25, 2005

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

IN RE: ATLANTA GAS LIGHT COMPANY'S)
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DIRECT TESTIMONY OF LANE KOLLEN

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Lane Kollen. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with the firm of Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I earned a Bachelor of Business Administration in Accounting degree from the University of Toledo. I also earned a Master of Business Administration degree from the University of Toledo. I am a Certified Public Accountant, with a practice license, and a Certified Management Accountant.

I have been an active participant in the utility industry for more than twenty-five years, both as an employee and as a consultant. Since 1986, I have been a consultant with Kennedy and Associates, Inc., providing services to state government agencies and large consumers of utility services in the ratemaking, financial, tax, accounting, and management areas. From 1983 to 1986, I was a consultant with Energy Management Associates, providing services to investor and consumer owned utility companies. From 1976 to 1983, I was employed by The Toledo Edison Company in a series of positions encompassing accounting, tax, financial, and planning functions.

I have appeared as an expert witness on accounting, finance, ratemaking, and planning issues before regulatory commissions and courts at the federal and state levels on more than one hundred occasions. I have developed and presented papers at various industry conferences on ratemaking, accounting, and tax issues. I have testified in numerous proceedings before the Georgia Public Service Commission ("Commission"), including the last three Atlanta Gas Light Company ("AGLC") base rate proceedings in Docket Nos. 3780-U, 8390-U, and 14311-U. In addition, I have acted as the lead consultant on two audits performed by the Commission Staff of the affiliate transactions affecting AGLC and its costs for ratemaking purposes in Docket Nos. 13147-U and 14311-U. My qualifications and regulatory appearances are further detailed in my Exhibit___(LK-1).

Q. On whose behalf are you testifying?

A. I am offering testimony on behalf of the Georgia Public Service Commission Adversary Staff ("Staff").

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address and make recommendations regarding the Company's base revenue requirement. This testimony on revenue requirements is in addition to my panel testimony with Staff witness Mr. Wackerly on the Comprehensive Rate Plan ("CRP"), including the roll-in to base rates of the Company's PRP rider and the continuation of the Company's Performance Based Rate Plan ("PBR"), and my panel testimony with Staff witness Ms. Thebert on the Company's proposed economic development fund and energy conservation programs.

Q. Please summarize your testimony.

A. The Commission should reject the Company's proposal for at least five rate increases over the next three years that will collect an estimated $146.944 million if they are authorized as requested and without modification. The Company has requested a $25.633 million base rate increase, another $7.5 million in the form of an economic development surcharge rider increase, and estimates that its Pipeline Replacement Program ("PRP") will require an estimated $9.563 million increase in October 2005, another estimated $11.131 million increase in October 2006, and yet another estimated $8.943 million increase in October 2007.

In contrast to the Company's series of rate increases over the next three years, I recommend that there be no change in the Company's base rates in conjunction with the Staff recommendation that the Commission adopt a Comprehensive Rate Plan for the Company. The CRP results in no base rate increases, no economic development rider increase, and no PRP rate increases for the next three years due to the partial roll-in of the Pipeline Replacement Program ("PRP") rider of an amount equivalent to the base rate reduction that I recommend in the absence of this partial PRP roll-in to base rates. The CRP provides true rate stability to customers by using the overearnings generated by the current base rates to offset and levelize the future pipeline replacement costs.

I recommend that the Company's base rates be reduced by $55.576 million absent the partial PRP roll-in to base rates. The table below provides a summary of the revenue requirement issues addressed by the Staff that result in this base rate reduction absent the partial PRP roll-in to base rates. This revenue requirement includes the effects of the Southern Natural Gas acquisition with no allocation of those costs to the PRP, which is consistent with the Company's Alternative 1 Case. The specific revenue requirement issues and recommendations are discussed in more detail in my testimony and in the Direct Testimonies of Staff witnesses Mr. Steve Hill (rate of return on common equity), Mr. Charles King (depreciation), and Ms. Jamie Barber and Mr. Michael McFadden (panel testimony on revenues) and Ms. Michelle Thebert and myself (panel testimony on energy conservation programs and economic development fund and rider).

SUMMARY OF STAFF ADJUSTMENTS TO AGLC
REVENUE REQUIREMENT ($000)

Rate Base Issues	
Remove AGLS Net Plant	(5,558)
Include Pension Liability	(1,876)
Adjust Post Retirement Benefits Liability-Test Year Only	(587)
Adjust Accumulated Depr for Lower Depreciation Expense	624
Adjust ADIT for Lower Depreciation Expense	(242)
Include SNG for Test Year	4,301
Include CWC Effect of Staff Adjustments	652
Operating Income Issues	
Increase Test Year Revenues	($7,436)
Modify Proposed Depreciation Rates	($8,849)
Reduce Depreciation for Lower Actual Plant in Service	($1,278)
Reduce Lease Expense for Amort Caroline St Sale Gain	($2,683)
Correct AGLS Composite Ratio Cost Allocations	($2,955)
Reduce Incentive Compensation Allocation	($2,285)
Reduce Outside Services Allocation	($755)
Remove Increase to AGLS New Business Services	($800)
Include AGLS Allocated Interest Expense	$1,308
Include AGLS VNG Acquisition Cost Alloc Savings	($5,672)
Include AGLS NUI Acquisition Cost Alloc Savings	($11,344)
Reduce Property Tax Expense	($1,056)
Reduce Pension Exp to Remove Special Adjustment	($1,439)
Modify Pension Expense Assumptions	($1,861)
Reduce OPEB Expense to Test Year Projections	($561)
Reduce Group Insurance Expense to Test Year Projections	($574)
Reduce Other Operating Expenses to Remove Escalation	($2,626)
Remove Volumetric Increase in Utility Locate Costs	($500)
Remove Energy Conservation Programs	($4,000)
Include SNG for Test Year	$533
Rate of Return Issues	
Use Short Term Debt Rate for Test Year	($399)
Update Long Term Debt Rate	($2,849)
Reduce Return on Equity to 9.0%	($20,445)
Total Staff Adjustments to AGLC Request	($81,209)
Less: AGLC Requested Increase (Base Case)	$ 25,633
Total Staff Recommended Base Rate Reduction before PRP Roll-In to Base Rates	$ (55,576)
PRP Roll-In to Base Rates	$ 55,576
Net Staff Recommended Change in Base Rates	$ -

Certain of the issues on the preceding table relate to costs charged by AGL Services Company ("AGLS") to AGLC, including the Company's request for more than $20 million in phantom (non-existent) costs that either are not incurred directly by AGLC or by the AGLR affiliate that charges AGLC. These affiliate relationships and the transactions between AGLS and AGLC were the subject of a Staff audit performed in 2004, of which I was the lead consultant. A copy of the Affiliate Audit Report was provided to the

Commission and other parties, including AGLC, in Docket No. 14311-U. I have included a copy of the Affiliate Audit Report as my Exhibit___(LK-2) and will refer to it in conjunction with my discussion on the various affiliate issues that I address in my testimony. The Affiliate Audit Report detailed the affiliate structure and affiliate transaction process, described adjustments required by the Securities and Exchange Commission ("SEC") resulting from an audit conducted in 2003, identified and quantified additional revenue requirement issues, and recommended that the Commission adopt affiliate reporting guidelines similar to those adopted for Georgia Power Company in Docket No. 9355-U. The affiliate reporting guidelines adopted for Georgia Power Company were included in the Affiliate Audit Report as Appendix 5. In addition to the revenue requirement effects of the issues identified in the Affiliate Audit Report that I address in my testimony, I recommend that the Commission adopt the affiliate reporting guidelines addressed in the Affiliate Audit Report. The Company has elected to withhold any substantive response to the Staff Affiliate Audit Report in Docket No. 14311-U, and instead reserved its right to respond to the issues in this proceeding.

The remainder of my testimony consists of a section on rate base issues, a section on operating income issues, and a final section on rate of return issues.

II. RATE BASE ISSUES

<u>Other Postretirement Benefits Liability</u>

Q. Please describe the Company's reduction to rate base for the net other post-retirement benefits liability.

A. The Company reduced rate base by $22.396 million for the net other postretirement benefits liability. The Company projected the unrecovered postretirement benefits transition cost asset and the accrued postretirement benefits liability for the projected test year and the two twelve month periods subsequent to the projected test year. It then computed a three year average of the monthly amounts, which it used to reduce rate base.

Q. Should the Company's quantification of the reduction to rate base for the net other postretirement benefits liability be adopted?

A. No. The Commission should reject this quantification because it constitutes a selected post test year adjustment that is inconsistent with the use of a single projected test year for most other ratemaking components.

Q. What is the correct quantification of this reduction to rate base?

A. The correct quantification is $27.152 million. This is the amount projected by the Company only for the months during the projected test year and with no post test year adjustments.

Q. What is the effect on the revenue requirement of the correct quantification of this reduction to rate base?

A. The effect is to reduce the revenue requirement by $0.587 million. I computed this amount by multiplying the net reduction in rate base times the Company's requested grossed-up rate of return of 12.33%.

Pension Benefits Liability

Q. Please describe the Company's increase to rate base for the net pension benefits liability.

A. The Company increased rate base by $6.109 million to reflect the cumulative effects of an amortization of a pension gain, which reduced pension expense in prior years. The Company did not reduce rate base for the pension benefits liability projected for the test year. Instead, it utilized a return on the pension benefits liability to reduce pension expense. The Company utilized an 8.75% rate of return equivalent to the pension discount rate for this purpose. The Company also incorporated a return on a regulatory asset for the minimum pension funding obligation to increase pension expense. It utilized the same 8.75% rate of return for that purpose. I address these adjustments to pension expense in the Operating Income section of my testimony.

Q. Should rate base be reduced for the pension benefits liability projected for the test year?

A. Yes. Ratepayers are entitled to the rate base reduction for the pension benefits liability in the same manner as the rate base reduction for the other postretirement benefits liability previously addressed. Although the Company's quantification of pension expense provides some benefit to ratepayers, it does so only at an 8.75% rate of return compared to the Company's requested overall rate of return of 12.33%. There is no reasonable basis for providing the ratepayers with only an 8.75% rate of return on this rate base amount.

Q. What is the revenue requirement effect of your recommendation?

A. The effect is to reduce the revenue requirement by $1.876 million. I computed this amount by multiplying the net reduction in rate base times the Company's requested grossed-up rate of return of 12.33%. I have reflected the related effects on the pension expense in the Operating Income section of my testimony.

AGL Services Company Net Plant

Q. Please describe the Company's proposal to include in its rate base the AGL Services Company (AGLS) net plant in the Company's rate base.

A. The Company has proposed to include in rate base an allocation of the net plant (gross plant in service less accumulated depreciation) that actually is owned by and included on the accounting books and records of AGLS. The Company has included $45.065 million in AGLS net plant in its rate base.

Q. What is the effect of the Company's proposal?

A. The effect of the Company's proposal is to include a non-existent cost of $4.250 million in excess of the actual costs charged by AGLS to the Company for the use of these assets. Pursuant to the requirements of the Public Utility Holding Company Act ("PUHCA"), administered by the Securities and Exchange Commission, AGLS is allowed to charge the affiliate companies to which it provides services, including AGLC, an allocation of its *actual* financing costs. In the historic test year, AGLC actually was charged $1.308 million of the interest AGLS incurred to finance its assets, which AGLC included in its operation and maintenance ("O&M") expenses.

In its filing, the Company eliminated this O&M expense and instead included an allocation of AGLS net plant assets in AGLC's rate base. Including an allocation of AGLS net plant in AGLC rate base had the effect of increasing the AGLC revenue requirement by $5.558 million, computed as the net plant amount of $45.065 million times the requested 12.33% overall rate of return. Thus, the excess cost included in the Company's revenue requirement is $4.250 million, the difference between the actual AGLS interest expense allocated to AGLC in the historic test year and the $5.558 million included by the Company in the revenue requirement.

Q. Mr. Morley argues that including the allocated AGLS net plant amount in AGLC's rate base is equitable because the assets serve AGLC. Please respond.

A. The Commission should reject this argument. Although there is no question that the assets are used to provide services to the Company, AGLS provides those services as a vendor to the Company, much like a third party provider of professional services. AGLS includes its actual financing costs in its charges to AGLC, which AGLC recognizes as O&M expense. AGLS owns these assets, and as such, finances these assets. AGLC does not own these assets and the Company's proposal is inconsistent with reality.

The issue is not whether the assets are used to serve AGLC, but rather what is the actual cost of using the assets to serve AGLC. The actual cost of the assets to serve AGLC is $1.308 million, the amount charged to AGLC in O&M expense for the historic test year. AGLS is capitalized at nearly 100% debt and its costs for these assets are lower than if AGLC had financed them. That is one advantage of the holding company and service company structure. The Company's proposal serves only to improperly increase the revenue requirement; it does not reflect reality. As such, the Company's proposal includes $4.250 million in excess costs that it actually does not and will not incur. It would be inequitable to charge ratepayers more than the actual cost incurred by the Company for the use of these assets.

Q. Was the Company consistent in reflecting the AGLS assets in all components of the revenue requirement?

A. No. The Company's proposal not only fails the actual cost test, it also fails the consistency test. Although its proposal would treat the AGLS assets as if they were AGLC's, the Company did not compute depreciation expense on these assets using AGLC's depreciation rates. If it had done so, the depreciation expense would have been lower than the amount included by the Company in its filing. In addition, the Company failed to reduce the revenue requirement for the reduction in rate base due to the accumulated deferred income taxes

("ADIT") related to the AGLS net plant assets. Thus, even if the Company's proposal is adopted, the revenue requirement included in the filing is incorrect and excessive.

Q. Given your recommendation to exclude the AGLS net plant from rate base, should the AGLS interest be included as an operating expense?

A. Yes. I have included the historic test year interest expense as an increase to the revenue requirement. Such treatment is consistent with the manner in which AGLC actually recognizes the AGLS interest charge.

Q. Why did you include the historic test year AGLS interest expense charged to AGLC in the revenue requirement rather than the projected test year interest expense?

A. I did so because the Company refused to provide a computation of the AGLS interest expense for the projected test year in response to STF-4-16 or STF-S4-16, arguing that it had not prepared such a computation because it chose to file its case by including the AGLS net plant in AGLC's rate base as if it were owned by AGLC. I have attached a copy of the Company's responses as my Exhibit___(LK-3). Consequently, I used the best proxy available for this amount from the historic test year.

Accumulated Depreciation and Accumulated Deferred Income Taxes

Q. Have you adjusted the Company's projected accumulated depreciation and ADIT to reflect the Staff's recommended depreciation rates and the resulting depreciation expense?

A. Yes. I have incorporated the Staff's recommended depreciation rates not only in depreciation expense, but also in the accumulated depreciation and ADIT for the test year. I also have incorporated the effects of the Staff's adjustment to reduce depreciation expense due to actual lower plant in service amounts at November 30, 2004 than were projected by the Company in the accumulated depreciation and ADIT for the test year.

Cash Working Capital

Q. Have you computed the cash working capital consistent with the Staff recommendations in this proceeding?

A. Yes. I have utilized the lead/lag days from the Company's filing, but adjusted the revenue and expense components for the Staff rate base, operating income, and rate of return recommendations. The computations are detailed on my Exhibit___(LK-4).

Summary of Rate Base

Q. Have you prepared a summary schedule of the Staff's recommended rate base?

A. Yes. This schedule is attached to my testimony as my Exhibit___(LK-5). It reconciles the Company's requested rate base with the Staff's recommended rate base.

III. OPERATING INCOME ISSUES

Operating Revenues

Q. Have you reflected in the Staff's recommended revenue requirement the increase in test year base revenues compared to the Company's filing sponsored by Mr. McFadden and Ms. Barber?

A. Yes. The adjustment to increase test year base revenues was provided to me by Mr. McFadden and Ms. Barber.

Depreciation Expense

Q. Have you reflected in the Staff's recommended revenue requirement the reduction in depreciation expense compared to the Company's filing sponsored by Mr. King?

A. Yes. The adjustment to reduce test year depreciation expense was provided to me by Mr. King. I also have reflected the effects of the reduction in depreciation expense on the accumulated depreciation and ADIT rate base components.

Q. Is there another adjustment to the Company's proposed depreciation expense that is necessary for the projected test year?

A. Yes. The Company's projection of plant in service at November 30, 2004 was much higher than its actual plant in service at that date. The Company's projected amount for that date was $2,583.394 million. The actual amount was $2,491.439 million, according to its November Grey Report filing, or $91.955 million less. PRP plant in service accounted for only $1.802 million of this difference.

Depreciation expense and the revenue requirement should be reduced by $1.278 million to remove the depreciation expense for the excessive plant in service at November 30, 2004 projected by the Company compared to the actual. The Company computed depreciation expense for the test year by multiplying its proposed depreciation rates times the average plant in service balance computed as the sum of the November 30, 2004 balance plus the

November 30, 2005 balance divided by 2. Mr. King computed the Staff adjustment to depreciation expense in the same manner in conjunction with the Staff recommended depreciation rates. I have computed the additional adjustment by changing the November 30, 2004 plant in-service balances from projected to actual amounts. I used Mr. King's proposed depreciation rates to compute the incremental revenue requirement effect of this adjustment.

Q. Do you propose a related adjustment to remove the excess projection of plant in service from rate base?

A. No. I have compared all major components of the Company's projected rate base at November 30, 2004 to the actual amounts at that date. Some components were higher; some were lower. However, the net result is that the projected rate base at November 30, 2004 was only slightly higher than the actual, by $1.461 million, which when divided by 2 to determine the average for the test year results in a difference of $0.731 million, with a revenue requirement effect of only $0.090 million. Consequently, I do not propose any adjustments to true-up the projected rate base amounts at November 30, 2004 to actual amounts.

<u>Energy Conservation Program Expense</u>

Q. Have you reflected in the Staff's recommended revenue requirement the reduction in expense to remove the costs of the Company's proposed Energy Conservation Program sponsored by you and Ms. Thebert?

A. Yes. I have removed the $4.000 million in total expense for the Energy Conservation Programs from the test year revenue requirement in accordance with the recommendation reflected in the panel testimony.

<u>Pension Expense</u>

Q. Please describe the Company's quantification of pension expense in its filing.

A. The Company projected pension expense for the projected test year and the two twelve month periods subsequent to the projected test year based on estimates provided by Mercer, a pension actuarial. The Company then computed the average pension expense over the three year projected period.

The Company provided and/or approved various information, including numerous assumptions, utilized by Mercer to project the pension expense for the three years. Among those assumptions was that AGLC would provide no additional funding to the pension plan in any of those three years despite the fact that the trust fund was underfunded. This assumption had the effect of increasing the projected pension expense because the trust fund amounts and earnings, which reduce pension expense, were lower than if the Company had assumed additional funding.

The Company further increased the projected pension expense to include a rate of return of 8.75% on a regulatory asset representing a minimum funding obligation and reduced the projected pension expense to reflect a rate of return of 8.75% on a pension benefits liability. The net effect of these two adjustments was to increase the pension expense by $1.439 million. Both the regulatory asset and the pension benefits liability were computed as the average monthly amount over the same projected three year period used for the development of the pension expense without these two adjustments.

Q. Should the Company's quantification of pension expense be adopted?

A. No. First, the Commission should reject the assumption that there will be no further funding of the pension trust fund during the next three years. This assumption incorrectly increases the projected pension expense. The Company likely will provide additional funding given the underfunded position of the trust fund, which will reduce the pension expense in the projected test year unless the trust fund assets appreciate in value substantially in excess of the rate of earnings reflected in the pension expense computation. The latter circumstance is substantially similar to increased funding and will result in lower pension expense.

Second, the Commission should reject the Company's selective post test year adjustment to pension expense for the two years beyond the end of the projected test year because it constitutes a post test year adjustment for one ratemaking component that is inconsistent with the use of a single projected test year for most other ratemaking components.

Third, the Commission should reject the Company's attempt to minimize the return on the pension benefits liability rather than treating it as a rate base reduction in the same manner as the postretirement benefits liability and at the same rate of return.

Fourth, the Commission should reject the Company's attempt to increase pension expense to include a return on a regulatory asset for the minimum pension funding obligation. The Company has not requested, nor has the Commission authorized a regulatory asset for this amount. Even if the Company had requested and the Commission authorized such a regulatory asset at some point in the future, the Company agrees that this regulatory asset should not earn a rate of return. In Mr. Morley's discussion regarding a possible request in another proceeding for a regulatory asset for the minimum pension funding obligation ("OCI"), Mr. Morley stated there "would be no cost of service impact to the customer for an OCI regulatory asset." (Morley Direct at 35). I agree there should be no impact to the ratepayers.

Q. What is your recommendation regarding the Company's proposed pension expense amount?

A. I recommend that the Commission reject the Company's proposed pension expense in its entirety and instead utilize the most recent actual twelve month ending amount of $1.918 million, or $3.299 million less than the $5.217 million reflected by the Company in its filing. The Company's requested amount is based on speculation, unfounded assumptions, and incorrectly includes adjustments to earn a rate of return on a non-existent regulatory asset. In contrast, the historic test year amount has been objectively determined and is no longer subject to the assumptions the Company carefully selected for ratemaking purposes. Should the Commission choose to utilize the Company's projection of pension expense, then it should be reduced to $3.603 million for the projected test year only and exclude the increase for the return on the regulatory asset and the reduction for the return on the pension benefits liability.

<u>Other Postretirement Benefits Expense</u>

Q. Please describe the Company's quantification of other postretirement benefit expense in its filing.

A. Similar to the computation of pension expense, the Company projected OPEB expense for the projected test year and the two subsequent twelve month periods based on estimates by Mercer. The Company quantified the OPEB expense as the average of the three years of projected expense amounts.

Q. Should the Company's quantification of OPEB expense for the test year be adopted?

A. No. The Commission should reject the Company's selective post test year adjustment to OPEB expense for the two years beyond the end of the projected test year because it constitutes a post test year adjustment for one ratemaking component that is inconsistent with the use of a single projected test year for most other ratemaking components.

Q. What is your recommendation regarding the OPEB expense amount?

A. I recommend that the Commission use the Company's projected amount for the test year with no post test year increase for the subsequent two years. This amount is $2.975 million, which is $0.561million less than reflected by the Company in its filing.

<u>Group Insurance Expense</u>

Q. Please describe the Company's quantification of group insurance expense in its filing.

A. Similar to the computation of pension and OPEB expense, the Company projected group insurance expense for the projected test year and the two subsequent twelve month periods based on estimates of projected growth in health care costs by its human resources personnel. The Company quantified the group insurance expense as the average of the three years of projected expense amounts. In response to STF 4-12, the Company failed to provide any computational support for the growth assumptions developed by its human resources personnel despite a follow-up request. Instead, the Company simply provided the results of a survey that reflected higher growth rates than incorporated in its projections.

Q. **Were you able to assess the validity of the Company's assumptions underlying the projected increase in group insurance expense?**

A. No. This is a particular problem because these assumptions drive the amount of the expense. The assumptions include the Company's experience, employee premium charges, and levels of employee deductibles and co-pays.

Q. **What is your recommendation for group insurance expense?**

A. Despite the inability to assess the validity of this projected expense, I recommend that the Commission include the $6.009 million amount projected for the test year, but exclude any increases projected for the two years following the test year. The test year amount is $0.574 million less than the amount included by the Company in its requested revenue requirement and computed as the average of the test year and the two years following the test year.

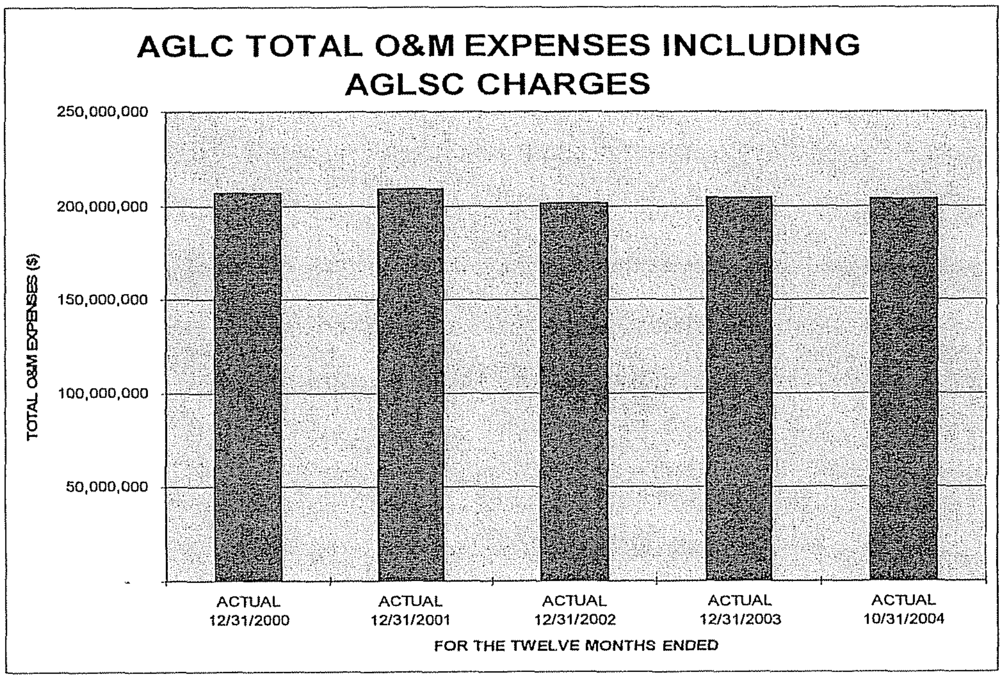
<u>Other Expenses Projected to Increase by Inflation</u>

Q. **Please describe how the Company projected other operation and maintenance expenses included in the projected test year.**

A. The Company projected most of the other operation and maintenance ("O&M") expenses included in the projected test year by applying an inflation rate of 3.21% to historic test year amounts. These expenses included both those incurred directly by AGLC and those charged to AGLC by AGLS. The Company included an increase in O&M expense and the revenue requirement of $2.626 million for inflation utilizing this methodology.

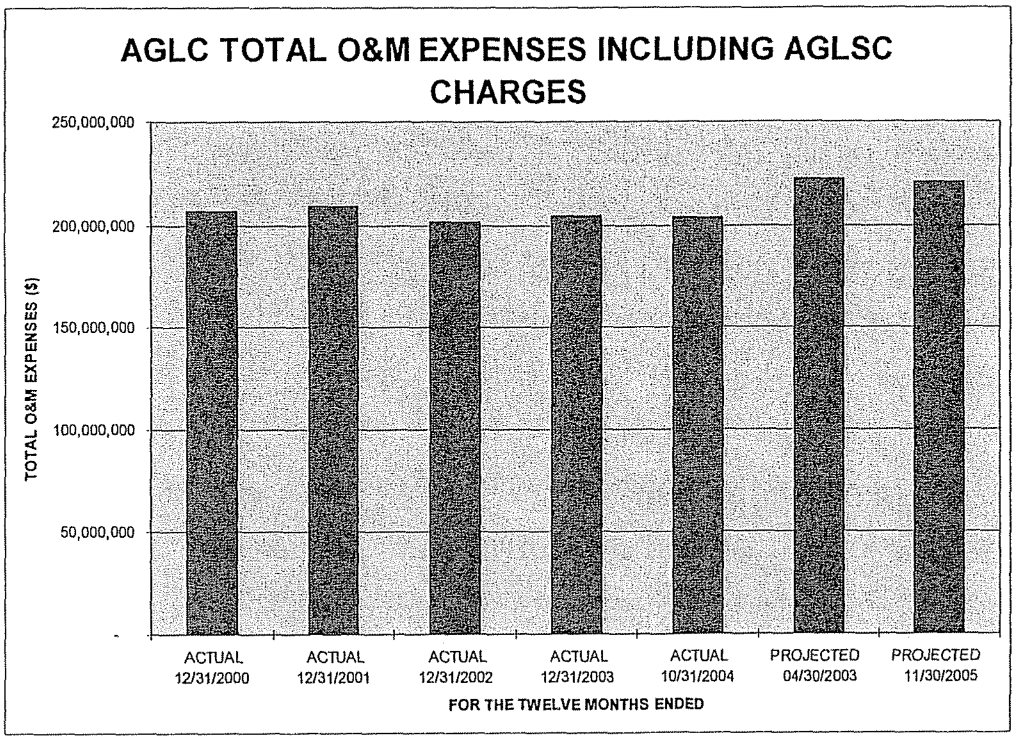
Q. Is it reasonable to project the O&M expenses for the projected test year in this manner?

A. No. This methodology completely ignores the reality of the Company's demonstrated ability to control cost growth, primarily through productivity gains implemented by both process improvement and investment in technology. The following chart demonstrates the Company's success in controlling the growth in total O&M expenses, including payroll, pension, OPEB, and group insurance expense. The information on this chart was taken from the Company's Grey Report filings to the Commission.



Q. How does the Company's projected O&M expense included in its filing compare to its actual O&M expense for the last five years?

A. The Company's projected O&M expense included in its filing is significantly in excess of its actual O&M expense for the last five years. The following chart compares the Company's actual O&M expense for the last five years to its request in this proceeding. I also have shown the Company's request in Docket No. 14311-U compared to the actual O&M expense so that the Commission can assess the reasonableness of the Company's two most recent ratemaking requests to its actual cost experience. The actual information on this chart was taken from the Company's Grey Report filings with the Commission. The requested O&M was taken from the Company's filings in Docket No. 14311-U and in this proceeding, with certain adjustments to ensure a consistent presentation of O&M expense from these filings to the Company's actual amounts.



Q. What adjustments have you made to the Company's O&M expense in the Docket No. 14311-U filing and in this proceeding for purposes of the preceding chart?

A. I have made three changes to the O&M expense included in the Company's filings in the two proceedings to ensure that O&M expense is stated on a consistent basis compared to the actual amounts on the preceding chart. In its ratemaking filings, the Company removed the AGLS charges to AGLC for depreciation, other taxes, and actual interest from the Company's O&M expense. I simply added the three amounts back to the Company's O&M expense.

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In actual O&M expense, as reported in the Grey Report filings, the Company includes the AGLS depreciation, other taxes (primarily property tax expense and payroll tax expense), and actual interest expense allocated to AGLC. However, for purposes of its revenue requirement filings in the two proceedings, the Company reclassified the first two components of these AGLS expenses from AGLC's O&M expense to depreciation expense and other taxes expense, thus appearing to reduce O&M expense for the test year compared to actual amounts. The Company also eliminated the AGLS interest expense charged to AGLC from AGLC's O&M expense and instead added the AGLS allocated net plant to AGLC's net plant to create a non-existent cost to artificially increase AGLC's revenue requirement. This had the effect of appearing to reduce O&M expense for the test year compared to actual amounts. I simply reversed the Company's three reclassifications made for purposes of the revenue requirement filings so that they were consistent with the actual amounts.

Q. How has the Company successfully achieved almost no growth in its O&M expenses, despite inflation pressures and other specific cost increases in expenses such as pension expense, OPEB expense, and group insurance expense?

A. The Company has controlled its costs through a focus on cost control, including the adoption of best practices within the industry and the investment in and implementation of technology to improve productivity. Improvements in productivity allow the Company to use fewer resources to accomplish required activities. Recent investments in technology include the implementation of the Marketer Interface Automation System ("MIA") and the implementation of Peoplesoft's Project Costing System and Time and Labor System. The Company described its use of technology to control or reduce operating expenses in its 2004 SEC 10-K filing under the heading ***Demonstrated track record of performance through superior execution*** as follows:

> We continue to focus our efforts on generating significant incremental earnings improvements from each of our businesses. We have been successful in achieving this goal in the past through a combination of business growth and controlling or reducing our operating expenses. We

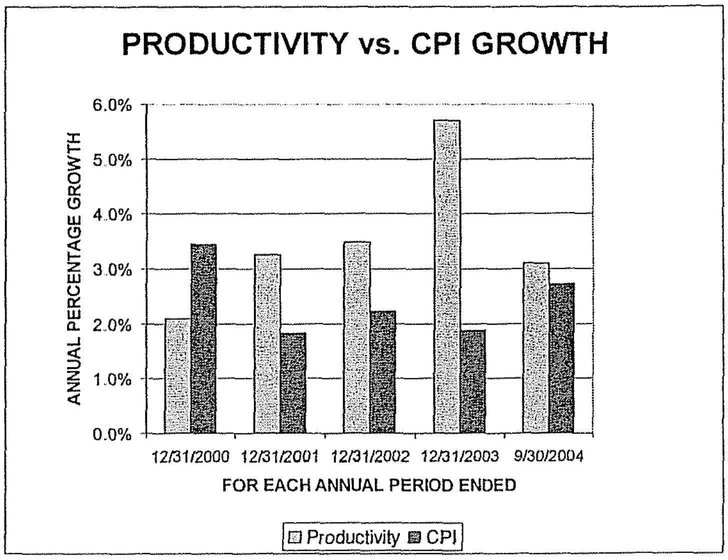
> achieved these improvements to our operations in part through the implementation of best practices in our businesses, including increased investments in enterprise technology, workforce automation and business process modernization.

The Company considers the investment in and implementation of technology to be an important component of its strategy of controlling costs. The Company's use of technology to drive increases in productivity and reductions in costs is prominently featured in AGLR presentations to securities analysts. Copies of presentation slides from recent conferences addressing the Company's use of technology for this purpose are attached as my Exhibit___(LK-6).

As detailed in these presentations, one of the Company's 2004 goals was to "drive incremental productivity through technology." Another slide described the Company's "increased productivity" due to "technology initiatives in 2004," which it identified as "GPS, Marketer Self-Serve, and Work Management."

Q. How do the Company's efforts to improve productivity and control growth in O&M expenses compare to national averages in productivity improvement?

A. In recent years, there has been a surge in productivity as reflected in the nonfarm productivity measure published by the U.S. Bureau of Labor Statistics. This productivity growth has more than offset cost escalations as measured by the CPI, the same measure used by the Company to project its test year O&M expenses compared to historic test year levels. The following chart compares productivity growth by year to inflation growth as measured by the CPI.



Based on national productivity experience compared to CPI inflation, there should be no increase in the Company's projected test year O&M expense compared to the historic year. This conclusion is consistent with the Company's actual experience as I previously demonstrated.

Q. Has the Company included all its actual and projected test year investments in technology to improve productivity in rate base in its filing?

A. Yes. This is a critical point as well. If the ratepayers pay for the technology to drive the productivity improvements, then they should receive the benefits of the attendant cost reductions. The Company's filing reflects the first part of this equation, but not the latter.

Q. What is your recommendation regarding the Company's proposal to increase O&M expense for projected CPI inflation?

A. I recommend that the Commission reject this proposal. The Company's proposal is inconsistent with the Company's actual success in controlling O&M expense growth. It is inconsistent with the increase in national productivity that has outstripped inflation. It is inconsistent with the Company including in rate base the cost of the investment in technology that it incurred to achieve those gains in productivity. It is inequitable to require that the ratepayers pay for the technology but not include the benefits of reduced O&M expense that were the very reason for the technology investment.

<u>Utility Locate Costs</u>

Q. Please describe the Company's request for a volumetric increase in utility locate costs.

A. The Company has increased O&M expense by $0.500 million based on the assumption that the number of its utility locates will increase volumetrically by more than 7%. The Company failed to provide any reason for its assumption of a volumetric increase in such utility locates, despite the Staff's request for that information in STF 4-30. There is no reason to simply accept this assumption in the absence of some compelling evidence that locates will increase by this magnitude.

The Company also included $0.200 million for increased contractor costs above the proposed $0.500 million volumetric increase. The Staff does not oppose the $0.200 million portion of the requested increase.

Q. How does the Company's assumption of huge increases in utility locate activity compare to its assumptions regarding miscellaneous service revenues?

A. Interestingly enough, the Company projected no increase in miscellaneous service revenues in the projected test year compared to the historic test year. If indeed the Company's projection of increases in utility locate activity was reasonable, then miscellaneous service also should be increased.

Q. What is your recommendation?

A. I recommend that the Commission reject this adjustment to increase O&M expense unless there is some compelling evidence that locates will increase by the magnitude assumed and that such increases also do not affect miscellaneous service revenues.

Property Tax Expense

Q. Please describe the Company's request for property tax expense in the projected test year.

A. The Company quantified property tax expense of $15.058 million based on the assumption of a different and higher valuation methodology that has not been used in prior years, except for 2004, and that was reversed by the Georgia Department of Revenue upon appeal by the utilities in the state. $1.056 million of the requested property tax expense is due to the Company's assumption that the Georgia Department of Revenue will propose and successfully implement a new valuation methodology. The sole support for this assumption identified by the Company in response to STF 4-7 was that an employee of the Department of Revenue strongly supports the higher valuation methodology and, as a result, will likely seek to impose it on the Company for the projected test year.

Q. Should the Commission adopt the Company's assumption that the Department of Revenue will change its valuation methodology for the projected test year, and that if it does, the utilities in the state will not be successful in their appeals?

A. No. This assumption is speculative at best given the paucity of support provided to the Staff and the success of AGLC and the other utilities in the state in defeating the Department of Revenue's attempted application of it in 2004. In addition, the Commission rejected Georgia Power Company's request to make a similar adjustment in its recent rate case in Docket 18300-U.

Q. Should the Company be allowed to include the increased property tax expense associated with its increased plant investment?

A. Yes. The Staff does not dispute that the Company should recover the projected test year increase in property tax expense associated with its increased plant investment.

Q. Have you calculated the proper amount of property tax expense for the test year?

A. Yes. The Company should be allowed to increase its property tax expense in the projected test year compared to the historic test year by the percentage increase in net assets over that same time period. Net plant increased by 10.34% from the historic year to the projected test year. This percentage increase multiplied by the historic year property tax expense yields an increase in expense of $1.312 million in the projected test year. No specific adjustment was necessary to include this level of expense because it already was included by the Company in its filing.

<u>Gain on Sale of Caroline Street Facilities</u>

Q. Please describe the relocation of the Company's and AGLS' offices to Ten Peachtree Place and the sale of the Caroline Street facilities.

A. In early 2003, AGLC and other affiliates, including AGLS, moved their offices from owned facilities on Caroline Street and leased facilities at the Biltmore to new leased facilities at Ten Peachtree Place. Most of the relocation costs were covered by the lessor of Ten Peachtree Place and are recovered by the lessor through the lease charges to AGLC and AGLS. AGLS incurred $18 million for leasehold improvements, furniture, and other fixed assets at the new location, which it amortizes and depreciates to expense and then charges to other affiliates, including AGLC. The lease expense incurred at the Ten Peachtree Place location is $5.7 million annually for both AGLC and AGLS. This compares to no lease costs and minimal other facilities costs at the Caroline Street location.

The Caroline Street facility included land owned by AGLC, two buildings owned by AGLS, and office furniture and equipment owned by both AGLC and AGLS. AGLC sold the land to a developer at a gain over net book value of $21.463 million, which it recorded below the line. Of that gain, the Company contributed $8.000 million to AGL Resources Private Foundation, Inc., a nonprofit foundation that makes charitable donations to qualified tax-exempt organizations. None of the AGLC gain was deferred or reflected as an offset to the lease expense in the projected test year.

In addition, instead of moving most of its fixed assets from the Caroline Street location to the new Ten Peachtree Place location, AGLS contributed these assets to various charitable organizations, including the Hosea Feed the Hungry & Homeless, YWCA, Education First, The Clean Air Campaign and Leadership Atlanta. AGLS recorded this contribution as a loss on the disposition of fixed assets, of which AGLC was allocated a portion during the historic test year. None of this AGLS charitable contribution or loss was included by the Company in the projected test year.

A more extensive discussion of the office relocation and the effect on AGLS and AGLC costs is included in the Staff's Affiliate Audit Report attached as my Exhibit___(LK-2).

Q. Should the gain from the sale of the land at the Caroline Street location be used to offset the substantial increase in facilities expense, including the lease expense and depreciation/amortization expense, associated with the relocation of the AGLC and AGLS offices to Ten Peachtree Place?

A. Yes. The gain should be deferred and amortized over the remaining life of the lease to reduce the substantially higher cost of the lease and depreciation/amortization to ratepayers compared to the cost of remaining at the Caroline Street location. There will be approximately eight years remaining on the Ten Peachtree Place lease on the effective date of the rates set in this proceeding.

Q. Should the Commission reduce the gain by the amount contributed to AGL Resources Private Foundation, Inc.?

A. No. The Commission historically has not allowed utilities to recover charitable contributions through rates. In recognition of this fact, AGLC has not requested recovery of its charitable contribution expense in its filing. The general principle underlying the disallowance of such costs is that ratepayers should not be forced to provide charitable contributions through the ratemaking process, although the Company and its affiliates are not precluded by the ratemaking process from making such discretionary contributions.

Q. The Company asserted during the Affiliate Audit in Docket No. 14311-U that none of the gain should be provided to ratepayers because FERC accounting standards require that such gains be recorded below the line. Do you agree?

A. No. The FERC does not have authority over retail ratemaking. The Commission has the ratemaking authority to require AGLC to defer this gain and to amortize it over the remaining term of the Ten Peachtree Place lease to partially mitigate the increased expense and revenue requirement associated with the higher costs of the new location. The accounting for this gain will follow the ratemaking, not vice versa.

Q. What is the effect of your recommendation to amortize the gain on the sale of the Caroline Street facilities over the remaining term of the lease at Ten Peachtree Place?

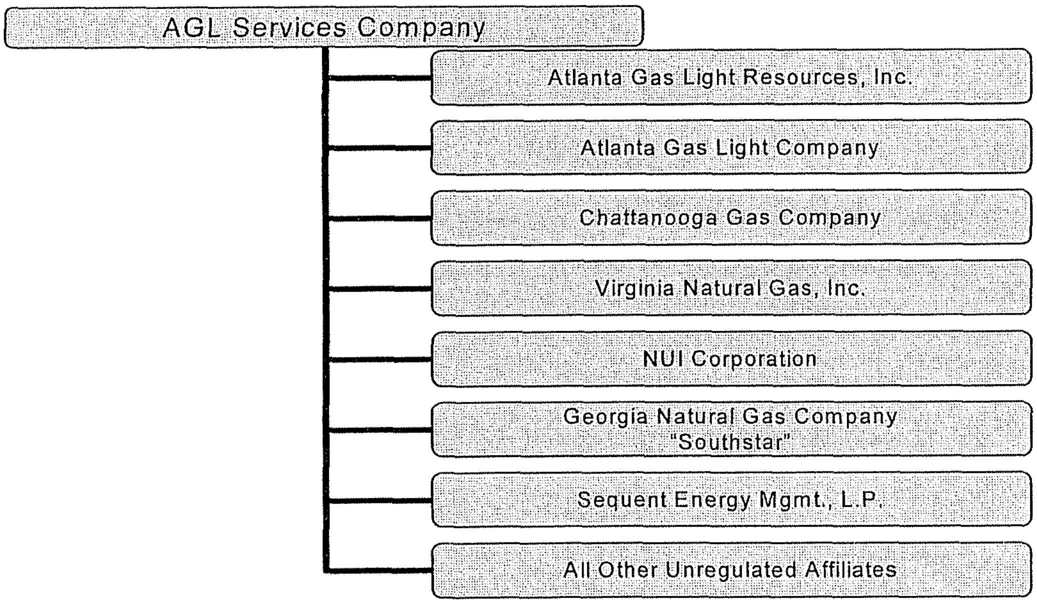
A. The effect is to reduce the revenue requirement and to offset the substantially increased expense associated with the Ten Peachtree Place location by $2.683 million. I computed this effect by dividing the $21.463 million gain on the sale of land by the remaining eight year term of the lease. The Commission may also wish to consider whether the gain should be used to reduce rate base in the same manner that deferred expenses are used to increase rate base. If the Commission includes the gain as a reduction to rate base, then the revenue requirement should be reduced by another $2.647 million, computed by multiplying the deferred gain of $21.463 million times the Company's requested 12.33% grossed-up rate of return.

Savings from AGLS Allocation of Costs to VNG

Q. Please describe the affiliate transaction process and the allocation of AGLS costs to each of the Company's affiliates including AGLC.

A. To comply with the requirements of the Public Utility Holding Act of 1935 ("PUHCA"), AGLS was formed as a mutual service company in order to provide centralized services to all regulated and non-regulated AGLR affiliates including AGLR retained. These centralized services consist of services obtained from third parties by AGLS and the internal costs of AGLS, including payroll, benefits, and other overhead costs. All costs are charged monthly to the various AGLR affiliates through a "chargeback" process, consisting of direct charges, direct assignments, and allocations. The majority of these costs are charged to AGLC, the Company's largest regulated gas provider. For the historic test year ended June 30, 2004, $101.244 million was charged to AGLC through this affiliate process. This amount represented 36% of AGLC's total operating expenses.

The chart below summarizes the major affiliates that receive or will receive services from AGLS.



A full description of the entire affiliate process along with the complete AGLR affiliate structure is included in the Affiliate Audit Report attached as my Exhibit___(LK-2).

Q. Please describe the Company's request for an increase to AGLC expense for 50% of the actual savings in AGLS charges to AGLC due to the acquisition of Virginia Natural Gas in 2000.

A. The Company has requested a non-existent expense of $5.672 million, one that it does not actually incur, for 50% of the savings in lower charges from AGLS resulting from the VNG acquisition. AGLR acquired VNG in October 2000. AGLR transferred various functions from VNG to AGLS and reduced VNG's costs by displacing costs that VNG previously had incurred directly and replaced those costs with charges for services from AGLS. Many of the AGLS costs were fixed or semi-variable and increased substantially less than the costs that were displaced from VNG. As a result, the charges from AGLS to AGLC were actually reduced by $11.344 million for accounting purposes. The Company's proposed adjustment simply increases actual costs charged by AGLS to AGLC by $5.672 million as if 50% of the actual savings had not been achieved.

Q. Has the Commission previously authorized rates that provided for recovery of this non-existent expense in excess of the actual charges to AGLC from AGLS?

A. No. Contrary to incorrect claims by Company witnesses during the hearings on the Company's Direct Testimony, the Commission has not previously authorized rates providing for recovery of this non-existent expense. The revenue reduction in Docket No. 14311-U was the result of a settlement between the Commission and the Company. That revenue reduction was a "black-box" settlement, with no computational support or adjudication of the underlying issues. Although the Company proposed an adjustment to increase expense; the Staff opposed it. Thus, the fact that the Company proposed the adjustment in Docket No. 14311-U means nothing unless the Commission explicitly affirmed that the adjustment was reflected in the reset rates. It did not.

Nothing in that Order stated that rates were set in that case, or should be set in future cases, by providing the Company recovery of non-existent expenses in excess of its actual costs. Further, nothing in the order stated that rates were set, or should be set, by allowing the

Company to retain any portion of the actual reduction in allocated charges to AGLC from AGLS due to the VNG acquisition. In short, the Order in Docket No. 14311-U provides no precedent in support of the Company's proposed VNG adjustment to increase the revenue requirement in this proceeding.

In conjunction with the settlement, the Commission established the reporting requirements for the PBR. As such, it allowed an adjustment to include an increase in expenses in excess of the actual charges for PBR purposes, but only to quantify earnings above the upper threshold for sharing purposes. The Commission specifically denied the Company the ability to include the expense to quantify earnings if that would allow the Company to file for a base rate increase because its earnings were below the lower threshold. See Paragraph 5 of the Performance Based Rate Plan in Docket 14311-U. In other words, the Order provided that the Commission would not recognize this adjustment for purposes of allowing the Company to file a rate case due to earnings below the band. If the Commission would not even recognize the adjustment for purposes of allowing the Company to file a rate case, there certainly is no basis to argue that the Commission recognized or would recognize the adjustment in actually setting rates. Thus, even if the Docket No. 14311-U Order were to be considered precedential, that precedent would argue for the rejection of this non-existent expense to artificially increase the revenue requirement and to actually set rates in this proceeding.

Q. The Company argued in Docket No. 14311-U and again argues in this proceeding that the Commission should include this expense as an "incentive" for AGLR to acquire other companies. Do you agree?

A. No. The Commission does not need to provide AGLR incentives to acquire other companies. AGLR has acquired other companies at least three times, the VNG acquisition in 2000, the NUI acquisition in 2004, and the Jefferson Island Storage & Hub LLC acquisition in 2004, without any authorization from this Commission and without any incentive provided by this Commission prior to the acquisitions. An after the fact "incentive" to AGLR would be gratuitous and unnecessarily harmful to ratepayers.

In each of those acquisitions, the economics of the deals, including the rate plans approved by other Commissions in Virginia, New Jersey, and Florida for the VNG and NUI acquisitions, provided sufficient incentives for AGLR to complete them. There is no need for this Commission to provide additional incentives for deals that are already completed or any future deals that will be completed that are not subject to the Commission's prior authorization and that are not critical to the economics of the deals.

Q. Should the Commission allow the Company to recover an expense that it does not actually incur?

A. No. The Commission should reject this proposition. Fundamentally, a non-existent expense is not and cannot be a reasonable cost of providing service. Including such an adjustment in AGLC's revenue requirement was not a condition of the VNG merger. It was not even a factor in the economics of the merger. In fact, the Commission had no jurisdiction over the merger; AGLR never sought authorization from the Commission to acquire VNG, NUI, or Jefferson Island. Thus, the expense is purely gratuitous, a taking from ratepayers for the sole purpose of increasing the Company's return for AGLR and its shareholders.

<u>Savings from AGLS Allocation of Costs to NUI</u>

Q. Please describe the Company's requested treatment of the costs and savings from the recent acquisition of NUI.

A. The Company has requested that no savings from the acquisition of NUI be reflected in the rates set in this proceeding. These savings actually will be achieved in the same manner as they were in the acquisition of VNG, i.e., through lower charges from AGLS to AGLC. The largely fixed costs of AGLS will be partially charged to NUI during the projected test year, which will result in lower charges of AGLS costs to AGLC. The Company has offered not to charge AGLC for any of the costs associated with the acquisition and integration of NUI into AGLR and AGLS and has offered not to provide any of the savings to AGLC until a "future rate proceeding," in which it would offer only then to share 50% of the actual savings with AGLC ratepayers. (O'Brien Direct at 16).

Q. How would the Company's proposed treatment of the savings be accomplished for Grey Report and PBR purposes over the next three years?

A. The Company's proposal is that it will artificially increase its actual costs by adding back to actual expense 100% of the savings achieved due to the NUI acquisition for Grey Report and PBR purposes. The Company's proposal extends for the next three years if the PBR is continued or until rates are reset again. In other words, the Company's proposal is to reflect NO savings, not even 50%, in the rates set in this proceeding or in the PBR during the next three years.

Q. Mr. O'Brien told the Commission during his cross-examination that the NUI savings would flow through the PBR and that savings would be shared with ratepayers to the extent the Company's earnings exceed the upper earnings threshold. Is that representation consistent with Mr. O'Brien's prefiled Direct Testimony?

A. No, not unless the Company has changed its offer. Specifically, Mr. O'Brien stated in his Direct Testimony the following:

> As such, for the period of this PBR extension, the Company proposes to track the costs and savings related to the NUI acquisition and eliminate any impact, positive or negative, to AGLC's cost of service. This would be accomplished through an adjustment in the Company's Grey Report filed monthly with this Commission.

Thus, the Company's proposal is that there will be NO savings shared with ratepayers, not directly through the rates set in this proceeding and not through the operation of the PBR over the next three years, assuming that it is continued.

Q. How does NUI compare in various size measures to the VNG acquisition and what effect does this have on the AGLS charges to AGLC?

A. NUI is larger than VNG by most, if not all, relevant measures, including customers, total employees, total assets, total expenses, and margins, all measures used to allocate AGLS fixed costs to the AGLR affiliates. The larger size of NUI will result in savings in AGLS charges to AGLC of an even greater amount than the VNG acquisition, all else equal. The Company's computation of savings in AGLS charges to AGLC from the VNG acquisition is $11.344 million. Consequently, the savings in AGLS charges to AGLC from the NUI acquisition should be at least that amount and most likely substantially more.

Q. Has the Company provided a quantification of the savings from the NUI acquisition?

A. No. The Staff requested that the Company provide a copy of the AGLR study(ies) assessing the economics of the NUI acquisition, which would have included the quantification of savings from achieving efficiencies that it relied upon for its decision to make the acquisition. The Company objected to providing this study in its initial response to STF-4-38 (b) and again in its supplemental response STF-S4-38 (b), copies of which are attached as my Exhibit___(LK-7).

In addition, the Company was asked to provide any computations that it had performed to quantify such savings in STF 6-30. In response, the Company provided only a trade secret preliminary quantification used for initial 2005 budgeting purposes, claiming that it had not performed a study that included "all" costs and savings and that the preliminary study should not be relied on in this proceeding. I agree that this computation is not useful, was not actually used by AGLR or AGLC for any purpose, and should not be relied on for any reason in this proceeding.

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Q. The Company has agreed not to charge AGLC for any of the acquisition or integration costs for the NUI acquisition. Would such costs have been charged to AGLC in the absence of such an offer or agreement from the Company?

A. No. Such costs would be directly assigned to NUI or retained by AGLR pursuant to the accounting practices of both AGLR and AGLS. This accounting treatment was confirmed by the Company in responses to STF–4-36 and STF-4-37, copies of which are attached as my Exhibit___(LK-8). Consequently, this component of the Company's offer has no value whatsoever. The offer only confirms that the Company will not attempt to circumvent the required accounting process to include these acquisition or integration costs for AGLC ratemaking purposes, which it cannot do anyway without Commission authorization.

Q. The Company has argued during cross examination of Mr. O'Brien that there will be savings, but it cannot quantify those savings and it does not know when they will be achieved. Do you agree with this assessment?

A. No. AGLR has a demonstrated track record of integrating its acquisitions and reducing costs expeditiously. AGLR would not have proceeded with the acquisition of NUI without an analysis of savings and a timetable to achieve those savings. Although it objected to providing the studies it relied upon for the acquisition in this proceeding, Mr. O'Brien confirmed, on cross examination, that AGLR indeed had prepared such analyses. AGLR prepared quantifications of the savings and an estimated timetable to achieve those savings to justify its acquisition of NUI, to demonstrate the economics to its Board of Directors, and to assure its investors. AGLR described the criteria and its application of those criteria to evaluate acquisitions such as NUI in its 2004 SEC 10-K filing under the heading ***Selectively evaluate the acquisition of natural gas assets*** as follows:

> We will selectively examine and evaluate the acquisition of natural gas distribution, gas pipeline or other gas-related assets. Our acquisition criteria include the ability to generate operational synergies, strategic fit relative to our core competencies, value from near-term earnings contributions and adequate returns on invested capital, while maintaining or improving our investment-grade credit ratings.

In addition, AGLR has moved expeditiously to achieve the savings from the NUI acquisition.

Shortly after the acquisition was consummated on November 1, 2004, AGLR implemented a major reorganization in December 2004 to integrate NUI into AGLR and to enable AGLS to provide centralized services to the NUI utilities. In the AGLR 2004 SEC 10-K filing under the heading of ***Rapidly integrate the NUI assets and achieve the resulting strategic benefits,*** AGLR stated the following:

> We are working to integrate NUI's assets into our portfolio of businesses and to provide the associated benefits to our customers and shareholders. Our integration plan includes applying enterprise-wide technology solutions and business processes that are designed to improve the key business metrics we track on a regular basis and bringing NUI's operations to a level of operational and service efficiency comparable to that of our other utility businesses.

Finally, AGLR has repeatedly told investors and the investment community that the acquisition of NUI "generates earnings accretion [increases] within the first year of closing," that there would be "EPS accretion within first year," and that there was a "joint transition operating team prior to closing – hit the ground running on Day One." In other words, outside the ratemaking world, AGLR is not the least hesitant to assert that it will achieve savings within the first year.

Q. Why should the Commission incorporate the savings in AGLS charges from the NUI acquisition in the revenue requirement rather than accepting the Company's offer to simply ignore them for ratemaking purposes until some future proceeding?

A. Fundamentally, these cost reductions will be implemented during the test year and should be incorporated in the revenue requirement in the same manner as any other projected rate base investment, operating expense, and cost of capital included in the Company's filing for the projected test year. It would be nonsensical to include various cost increases proposed by the Company, but to ignore the largest cost reduction of all. One of the primary objectives of ratemaking is to utilize the test year to measure the cost to provide service. If the costs will significantly decrease due to a known and measurable event, such as the NUI acquisition, then the cost reduction should be reflected in the revenue requirement for the test year.

Q. The Company has offered to share 50% of the NUI acquisition savings in a future rate proceeding. Should the Commission accept this proposal?

A. No. The savings should be reflected in their entirety in the rates set in this proceeding. There is no reason to wait for three or more years and then only to obtain at most 50% of the actual savings. This will create a huge disconnect between AGLC's costs reported for accounting purposes and the costs reported for ratemaking purposes. The Company will retain the entirety of the achieved savings if the PBR is continued unless its earnings exceed the upper threshold. The failure to include the savings in their entirety in the rates set in this proceeding will ensure that rates reflect phantom costs that the Company will not actually incur.

Incentive Compensation

Q. Please describe how you have defined the term "incentive compensation" and how it applies to the officers of AGLR.

A. I have used this term to describe the compensation pursuant to various plans paid to the officers of AGLR based primarily upon AGLR stock price appreciation of AGLR stock or other measures of AGLR financial performance, which includes the financial performance of the nonregulated AGLR affiliates. Incentive compensation is incurred to align the interests of AGLR executives more closely with that of AGLR shareholders. Incentive compensation is paid in the form of restricted stock, non qualified stock options, and stock appreciation rights.

Incentive compensation is expensed based on various vesting schedules at the current stock price. The expense is then driven from AGLS[1] to the affiliates, including AGLC, based upon payroll dollars of each affiliate through the direct charge process. All costs allocated to

[1] The officers of AGLR are employees of AGLS.

AGLS departments through the direct charge process are included in the overall department cost pool that is allocated to the AGLS affiliates, including AGLC. The only incentive compensation budgeted by the Company in 2004 were Performance Units and Restricted Stock as part of the LTIP plan. These plans are described in greater detail in the Affiliate Audit Report, a copy of which is attached as my Exhibit___(LK-2).

Based upon the Company's total expense allocations through the third quarter 2004, approximately 76% of the expense related to five officers of AGLR. This is the same number of officers that were deemed as shared employees of AGLR and AGLS by the SEC in the PUHCA audit and that are now included in the composite ratio calculations.

Q. What is your recommendation concerning incentive compensation for the officers of AGLR?

A. I recommend that such costs be excluded from allowed operating expenses. Incentive compensation tied to measures of AGLR stock price and financial performance are not caused by the provision of regulated utility service, but rather are caused by AGLR shareholders to enhance the value of their investment. Based on 2004 information supplied by the company, I have computed the amount of incentive compensation included in the Company's revenue requirement at $1.708 million.

Q. Please describe the AGLR Directors' incentive compensation plan.

A. The Non-Employee Directors Equity Compensation Plan ("Directors Plan") provides for the issuance of restricted stock to all non-employee directors. All costs related to the stock appreciation of AGLR stock is charged to the affiliates utilizing the composite ratio.

Q. What is your recommendation concerning incentive compensation for the Directors of AGLR?

A. Based on 2003 actual information supplied by the company during the Affiliate Audit, the estimated amount of incentive compensation included in the test year is $0.577 million. Just like the incentive compensation for officers, these costs should not be included for ratemaking and rate of return purposes. Such measures of stock price and financial performance are not caused by the provision of regulated utility service, but rather are caused by AGLR shareholders to enhance the value of their investment.

<u>Outside Services Improperly Charged by AGLS to AGLC</u>

Q. Please describe your adjustment to reduce the outside services allocation.

A. Historically, AGLC has been improperly charged by AGLS for the costs of certain outside services (consulting and legal) that either should have been retained by AGLR or charged directly to other affiliates. These improper charges were described in more detail in the Affiliate Audit Report attached as Exhibit___(LK-2), which covered the years 2002 and 2003 and in a previous Staff Affiliate Audit Report covering certain years prior to 2002. The Staff Affiliate Audit found that AGLC was improperly charged $1.146 million and $0.755 million, in 2002 and 2003, respectively, for such costs.

These errors appear to be continuing in nature based on the two Staff Audits, although it is impossible to audit actual invoices for a projected test period. Consequently, I assumed that there would be similar errors in the projected test period and chose the most recent audited amount for the quantification of this adjustment.

<u>Composite Ratio Computations</u>

Q. Please describe the AGLS Composite Ratio percentage used by the Company for computing the AGLS allocated expenses included in the test year filing.

A. The company based all of its allocations of costs by AGLS service provider using the same percentages as the first six months of 2004. The largest allocation factor for allocating AGLS pooled costs is the Composite Ratio. Please refer to the Report attached as my Exhibit___(LK-2) for a complete discussion of the Composite Ratio. The overall Composite Ratio average for the first six months of 2004 amounted to 55.59%. The total composite ratio charges allocated to AGLC for the first six months of 2004, based upon the 60-day letter SEC PUHCA methodology as reported in the Company's Grey Report, amounted to $19.322 million on an annualized basis.

Q. Should the Company's quantification of Composite Ratios for the test year be adopted?

A. No. The six months average approach used by the Company does not take into consideration changes that have been made to the affiliate structure since June 2004. For instance, the Jefferson Island Storage facility was added as an affiliate after June 2004. In fact, the Composite Ratio being used to allocate costs during the fourth quarter of 2004 was only 52.02%, including the Jefferson Island Storage facility, but excluding the NUI acquisition. Since the first month of the test year falls within the fourth quarter, the 52.02% Composite Ratio should be used instead of using the average of the first six months of 2004. Using this more recent Composite Ratio for the projected test year results in a reduction of AGLS charges allocated to AGLC of $1.240 million.

Q. Do you propose another adjustment related to the Composite Ratio?

A. Yes. As described in the Affiliate Audit Report, the Company has failed to include AGLR in all allocations using the Composite Ratio, although it now has included AGLR in the Composite Ratio for corporate governance costs. These costs include the costs of the IS&T, Purchasing, Business Support Facilities, Business Support Other, and Other departmental IDs that also are allocated using the Composite Ratio. The Composite Ratio should be modified to include AGLR for purposes of allocating these costs consistently with the allocation of corporate governance costs.

Q. Have you quantified the amount of charges that were inappropriately charged to AGLC rather than AGLR?

A. Yes. Using the same methodology as the SEC required for the corporate governance costs, I identified the annualized allocated amounts for each of the listed business functions from the Grey Report. I then revised the Composite Ratios used for these functions to include AGLR. Using the revised Composite Ratios, I recomputed the amounts that would be charged to

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AGLC for the test year, which resulted in a reduction of $1.715 million.

AGLS Charges for New Business Services

Q. Please describe the Company's request for an increase in charges allocated from AGLS to AGLC for new business services costs.

A. The Company has requested an increase of $0.800 million in such charges. These costs are marketing and promotional costs, although they were not described as such in the Company's filing. The Company described the proposed increase in allocated charges in response to STF 4-26 as follows:

> Due to increased competition from electric companies, namely local Electric Membership Corporations, AGLC has the need to increase its presence with the homebuilders and the touch points with both builders and developers. Disincentives for using natural gas in a development are difficult to overcome. The increase of $.8 million in the projected test year includes the following;
>
> - Additional sponsorships of homebuilder meetings and events
> - Increases in costs of production and distribution of AGLC sponsored publication that promotes builders who realize the benefits of natural gas in the new home market
> - The model home program that assists builders with promoting natural gas appliances and their respective benefits in their model homes.

Q. Should the Commission authorize recovery of the proposed increase in AGLS allocated new business services costs?

A. No. These costs are marketing and promotional costs, which the Commission historically has not allowed utilities to recover from ratepayers.

Summary of Operating Income

Q. Have you prepared a summary of the Staff's recommended operating income?

A. Yes. This schedule is attached to my testimony as my Exhibit___(LK-9). It reconciles the Company's requested operating income with the Staff's recommended operating income.

IV. RATE OF RETURN ISSUES

AGLC Financing and Capitalization

Q. Please describe how AGLC acquires new financing.

A. AGLS determines the types of amounts of financing that are provided by AGLR to the affiliates, including AGLC. AGLC does not engage in any financing activities with outside investors or manage its financing with other affiliates. All AGLC financing is controlled and obtained by AGLS through various AGLR affiliate entities. AGLR obtains financing for its affiliates through the issuance of AGLR equity to outside investors and by using AGL Capital Corporation to issue short term debt, long term debt, and preferred equity to outside investors. In addition, AGLR affiliates invest and borrow from each other on a short term basis from the AGLR Money Pool, an internal AGLR "bank" managed by AGLS.

AGLR then either lends to or invests equity in the other AGLR affiliate companies, including AGLC. Commencing on September 1, 2004, AGLS now sets the AGLC capital structure at the end of each month so that it is equal to the capital structure authorized by the Commission in Docket No. 14311-U. The capital structure authorized in Docket No. 14311-U is slightly different than the capital structure requested by the Company in this proceeding. AGLS then adjusts the amount of long term debt monthly through an adjustment to the principal amount of a note payable to AGLR and adjusts the amount of common equity monthly through an adjustment to the principal amount of a separate dividend payable to AGLR.

AGLC no longer issues any securities directly to the investing public, although it currently retains some debt issues that were issued directly to outside investors in previous years. Through AGL Capital Corporation, AGLR and the affiliate companies, including AGLC, are able to achieve economies that are intended to result in lower financing costs through consolidated and centralized financing.

<u>Short Term Debt Interest Rates</u>

Q. Please describe the Company's requested short term debt interest rate.

A. The Company requested a short term debt interest rate of 3.77%, computed as the average of projected short term debt interest rates for the projected test year and higher projected rates for the following two years, based on the LIBOR forward price curve, plus 16 basis points for the spread. (Morley Direct at 28). The projected short term debt interest rate for the test year is 2.96% without averaging in the following two years, based on the three month forward LIBOR rate from the date of this testimony plus 16 basis points for the spread. The three month forward rate provides the projected rate at the midpoint of the test year. I obtained the three month forward rate from the *Wall Street Journal* and confirmed it against the real-time rates available at www.FXStreet.com.

Q. What was the short term interest rate on AGLC borrowings at June 30, 2004?

A. The short term interest rate on AGLC borrowings at the end of the historic test year was 1.81%, according to the Company's response to STF 4-31.

Q. Should the Commission adopt the actual short term debt interest rate as of June 30, 2004?

A. No. It is appropriate to use the projected rate for the projected test year.

Q. Should the Commission adopt the Company's proposal to use an average of the projected short term debt interest rates including the two years following the test year?

A. No. This proposal constitutes yet another selective post test year adjustment to increase the revenue requirement and that undermines the consistency of the projected test year for all other ratemaking components. The statute provides for a projected test year, but not the extreme of three years into the unknown future.

Q. What is your recommendation for the short term debt interest rate?

A. I recommend that the Commission utilize the projected short term debt rate for the test year without consideration of the following two years.

Q. What is the revenue requirement effect of your recommendation to use the test year cost of short term debt rather than the Company's proposal based on a three year projection?

A. The effect of this recommendation is to reduce the revenue requirement by $0.399 million. I computed this amount by multiplying the rate base, after all adjustments recommended by the Staff, times the differential in the grossed-up rates of return without and with this adjustment. The two rates of return are shown on my Exhibit___(LK-10) in sections I and II on that schedule.

<u>Long Term Debt Interest Rates</u>

Q. Please describe the Company's requested long term debt interest rate.

A. The Company's requested long term debt interest rate is the average cost of long term debt and preferred equity based on the average cost of the AGL Capital Corporation long term debt and preferred equity outstanding at June 30, 2004. It does not reflect any short term debt issued by AGL Capital Corporation. The interest rate on the AGLC note payable to AGLR is based on the stated interest and dividend rates of the debt and preferred equity issued by AGL Capital Corporation and other AGLR financing affiliates, adjusted quarterly. The interest rate on the note payable does not reflect the lower cost of debt issued or other financing activities subsequent to June 30, 2004 nor does it reflect the effects on the average cost of debt resulting from interest rate swaps entered into by AGL Capital Corporation.

Q. Should the Commission utilize the long term debt interest rate proposed by the Company?

A. No. This rate is excessive and should be reduced to 6.64% to reflect the effects of $250 million in new long term debt financing at 6.0% by AGL Capital Corporation issued in

September 2004 and another $200 million at 4.95% issued in December 2004. All other rate base and operating income components are projected for the test year. There is no reason why the Commission should use the historic year average cost of long term debt rather than the most recent actual data to at least reflect known financings since the end of the historic test year.

Q. What is the revenue requirement effect of your recommendation to update the cost of long term debt?

A. The effect of this recommendation is to reduce the revenue requirement by $2.849 million. I computed this amount by multiplying the rate base, after all adjustments recommended by the Staff, times the differential in the grossed-up rates of return without and with this adjustment. The two rates of return are shown on my Exhibit___(LK-10) in Sections II and III on that schedule.

<u>**Return on Common Equity**</u>

Q. Have you quantified the effect on the revenue requirement of the Staff recommendation for the reasonable return on common equity sponsored by Mr. Steve Hill?

A. Yes. The effect of this recommendation is to reduce the revenue requirement by $20.506 million. I computed this effect by multiplying the rate base, after all Staff adjustments, times the difference in the grossed-up rate of return requested by the Company compared to the grossed-up rate of return with the Staff recommended return on common equity and the adjustments to the cost of short term debt and long term debt. The computations supporting the grossed-up rates of return are detailed on my Exhibit___(LK-10) in Sections III and IV of that schedule.

Q. Does this complete your testimony?

A. Yes.

EXHIBIT___(LK-1)

RESUME OF LANE KOLLEN, VICE PRESIDENT

EDUCATION

University of Toledo, BBA
Accounting

University of Toledo, MBA

PROFESSIONAL CERTIFICATIONS

Certified Public Accountant (CPA)

Certified Management Accountant (CMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Management Accountants

More than twenty-five years of utility industry experience in the financial, rate, tax, and planning areas. Specialization in revenue requirements analyses, taxes, evaluation of rate and financial impacts of traditional and nontraditional ratemaking, utility mergers/acquisition diversification. Expertise in proprietary and nonproprietary software systems used by utilities for budgeting, rate case support and strategic and financial planning.

RESUME OF LANE KOLLEN, VICE PRESIDENT

EXPERIENCE

1986 to Present:

J. Kennedy and Associates, Inc.: Vice President and Principal. Responsible for utility stranded cost analysis, revenue requirements analysis, cash flow projections and solvency, financial and cash effects of traditional and nontraditional ratemaking, and research, speaking and writing on the effects of tax law changes. Testimony before Connecticut, Florida, Georgia, Indiana, Louisiana, Kentucky, Maine, Minnesota, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, and West Virginia state regulatory commissions and the Federal Energy Regulatory Commission.

1983 to 1986:

Energy Management Associates: Lead Consultant.
Consulting in the areas of strategic and financial planning, traditional and nontraditional ratemaking, rate case support and testimony, diversification and generation expansion planning. Directed consulting and software development projects utilizing PROSCREEN II and ACUMEN proprietary software products. Utilized ACUMEN detailed corporate simulation system, PROSCREEN II strategic planning system and other custom developed software to support utility rate case filings including test year revenue requirements, rate base, operating income and pro-forma adjustments. Also utilized these software products for revenue simulation, budget preparation and cost-of-service analyses.

1976 to 1983:

The Toledo Edison Company: Planning Supervisor.
Responsible for financial planning activities including generation expansion planning, capital and expense budgeting, evaluation of tax law changes, rate case strategy and support and computerized financial modeling using proprietary and nonproprietary software products. Directed the modeling and evaluation of planning alternatives including:

Rate phase-ins.
Construction project cancellations and write-offs.
Construction project delays.
Capacity swaps.
Financing alternatives.
Competitive pricing for off-system sales.
Sale/leasebacks.

RESUME OF LANE KOLLEN, VICE PRESIDENT

CLIENTS SERVED

Industrial Companies and Groups

Air Products and Chemicals, Inc.
Airco Industrial Gases
Alcan Aluminum
Armco Advanced Materials Co.
Armco Steel
Bethlehem Steel
Connecticut Industrial Energy Consumers
ELCON
Enron Gas Pipeline Company
Florida Industrial Power Users Group
General Electric Company
GPU Industrial Intervenors
Indiana Industrial Group
Industrial Consumers for
  Fair Utility Rates - Indiana
Industrial Energy Consumers - Ohio
Kentucky Industrial Utility Customers, Inc.
Kimberly-Clark Company
Lehigh Valley Power Committee
Maryland Industrial Group
Multiple Intervenors (New York)
National Southwire
North Carolina Industrial
  Energy Consumers
Occidental Chemical Corporation
Ohio Energy Group
Ohio Industrial Energy Consumers
Ohio Manufacturers Association
Philadelphia Area Industrial Energy
  Users Group
PSI Industrial Group
Smith Cogeneration
Taconite Intervenors (Minnesota)
West Penn Power Industrial Intervenors
West Virginia Energy Users Group
Westvaco Corporation

Regulatory Commissions and Government Agencies

Georgia Public Service Commission Staff
Kentucky Attorney General's Office, Division of Consumer Protection
Louisiana Public Service Commission Staff
Maine Office of Public Advocate
New York State Energy Office
Office of Public Utility Counsel (Texas)

RESUME OF LANE KOLLEN, VICE PRESIDENT

Utilities

Allegheny Power System
Atlantic City Electric Company
Carolina Power & Light Company
Cleveland Electric Illuminating Company
Delmarva Power & Light Company
Duquesne Light Company
General Public Utilities
Georgia Power Company
Middle South Services
Nevada Power Company
Niagara Mohawk Power Corporation
Otter Tail Power Company
Pacific Gas & Electric Company
Public Service Electric & Gas
Public Service of Oklahoma
Rochester Gas and Electric
Savannah Electric & Power Company
Seminole Electric Cooperative
Southern California Edison
Talquin Electric Cooperative
Tampa Electric
Texas Utilities
Toledo Edison Company

Expert Testimony Appearances
of
Lane Kollen
As of January 2005

Date	Case	Jurisdict.	Party	Utility	Subject
10/86	U-17282 Interim	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
11/86	U-17282 Interim Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
12/86	9613	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Revenue requirements accounting adjustments financial workout plan.
1/87	U-17282 Interim	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements, financial solvency.
3/87	General Order 236	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Tax Reform Act of 1986.
4/87	U-17282 Prudence	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
4/87	M-100 Sub 113	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Tax Reform Act of 1986.
5/87	86-524-E-	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements. Tax Reform Act of 1986.
5/87	U-17282 Case In Chief	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Case In Chief Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Prudence Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.

Expert Testimony Appearances
of
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As of January 2005

Date	Case	Jurisdict.	Party	Utility	Subject
7/87	86-524 E-SC Rebuttal	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
8/87	9885	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Financial workout plan.
8/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
11/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Tax Reform Act of 1986.
1/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, rate of return.
2/88	9934	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Economics of Trimble County completion.
2/88	10064	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, O&M expense, capital structure, excess deferred income taxes.
5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric	Financial workout plan. Corp.
5/88	M-87017 -1C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery.
5/88	M-87017 -2C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery.
6/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1 economic analyses, cancellation studies, financial modeling.

Expert Testimony Appearances
of
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Date	Case	Jurisdict.	Party	Utility	Subject
7/88	M-87017- -1C001 Rebuttal	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery, SFAS No. 92
7/88	M-87017- -2C005 Rebuttal	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery, SFAS No. 92
9/88	88-05-25	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Excess deferred taxes, O&M expenses.
9/88	10064 Rehearing	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Premature retirements, interest expense.
10/88	88-170- EL-AIR	OH	Ohio Industrial Energy Consumers	Cleveland Electric Illuminating Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	88-171- EL-AIR	OH	Ohio Industrial Energy Consumers	Toledo Edison Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial Considerations, working capital.
10/88	8800 355-EI	FL	Florida Industrial Power Users' Group	Florida Power & Light Co.	Tax Reform Act of 1986, tax expenses, O&M expenses, pension expense (SFAS No. 87).
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Pension expense (SFAS No. 87).
11/88	U-17282 Remand	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Rate base exclusion plan (SFAS No. 71)
12/88	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87).
12/88	U-17949 Rebuttal	LA	Louisiana Public Service Commission Staff	South Central Bell	Compensated absences (SFAS No. 43), pension expense (SFAS No. 87), Part 32, income tax normalization.
2/89	U-17282 Phase II	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, phase-in of River Bend 1, recovery of canceled plant.

Expert Testimony Appearances
of
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As of January 2005

Date	Case	Jurisdict.	Party	Utility	Subject
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.
7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43), Part 32.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery, tax expense, revenue requirements.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.
9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
10/89	8880	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.
10/89	8928	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash working capital.
10/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements.
11/89 12/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements, sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements , detailed investigation.

Expert Testimony Appearances
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As of January 2005

Date	Case	Jurisdict.	Party	Utility	Subject
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan.
3/90	890319-EI	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	890319-EI Rebuttal	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Fuel clause, gain on sale of utility assets.
9/90	90-158	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, post-test year additions, forecasted test year.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements.
3/91	29327, et. al.	NY	Multiple Intervenors	Niagara Mohawk Power Corp.	Incentive regulation.
5/91	9945	TX	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Recovery of CAAA costs, least cost financing.
9/91	91-231 -E-NC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Recovery of CAAA costs, least cost financing.
11/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Asset impairment, deregulated asset plan, revenue requirements.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
12/91	91-410-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
12/91	10200	TX	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financial integrity, strategic planning, declined business affiliations.
5/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, pension expense, OPEB expense, fossil dismantling, nuclear decommissioning.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
9/92	92-043	KY	Kentucky Industrial Utility Consumers	Generic Proceeding	OPEB expense.
9/92	920324-EI	FL	Florida Industrial Power Users' Group	Tampa Electric Co.	OPEB expense.
9/92	39348	IN	Indiana Industrial Group	Generic Proceeding	OPEB expense.
9/92	910840-PU	FL	Florida Industrial Power Users' Group	Generic Proceeding	OPEB expense.
9/92	39314	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	OPEB expense.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy Corp.	Merger.
11/92	8649	MD	Westvaco Corp., Eastalco Aluminum Co.	Potomac Edison Co.	OPEB expense.
11/92	92-1715-AU-COI	OH	Ohio Manufacturers Association	Generic Proceeding	OPEB expense.
12/92	R-00922378	PA	Armco Advanced Materials Co., The WPP Industrial Intervenors	West Penn Power Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.

Expert Testimony Appearances
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As of January 2005

Date	Case	Jurisdict.	Party	Utility	Subject
12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger.
12/92	R-00922479	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	OPEB expense.
1/93	8487	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Bethlehem Steel Corp.	OPEB expense, deferred fuel, CWIP in rate base
1/93	39498	IN	PSI Industrial Group	PSI Energy, Inc.	Refunds due to over-collection of taxes on Marble Hill cancellation.
3/93	92-11-11	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	OPEB expense.
3/93	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	Merger. Corp.
3/93	93-01 EL-EFC	OH	Ohio Industrial Energy Consumers	Ohio Power Co.	Affiliate transactions, fuel.
3/93	EC92-21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	Merger. Corp.
4/93	92-1464-EL-AIR	OH	Air Products Armco Steel Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
4/93	EC92-21000 ER92-806-000 (Rebuttal)	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	Merger. Corp.
9/93	93-113	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Fuel clause and coal contract refund.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers and Kentucky Attorney General	Big Rivers Electric Corp.	Disallowances and restitution for excessive fuel costs, illegal and improper payments, recovery of mine closure costs.

Expert Testimony Appearances
of
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As of January 2005

Date	Case	Jurisdict.	Party	Utility	Subject
10/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Revenue requirements, debt restructuring agreement, River Bend cost recovery.
1/94	U-20647	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
4/94	U-20647 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Nuclear and fossil unit performance, fuel costs, fuel clause principles and guidelines.
5/94	U-20178	LA	Louisiana Public Service Commission Staff	Louisiana Power & Light Co.	Planning and quantification issues of least cost integrated resource plan.
9/94	U-19904 Initial Post-Merger Earnings Review	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
9/94	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policies, exclusion of River Bend, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Incentive rate plan, earnings review.
10/94	5258-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Alternative regulation, cost allocation.

Expert Testimony Appearances
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Lane Kollen
As of January 2005

Date	Case	Jurisdict.	Party	Utility	Subject
11/94	U-19904 Initial Post-Merger Earnings Review (Rebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Revenue requirements. Fossil dismantling, nuclear decommissioning.
6/95	3905-U	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund.
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission	Gulf States Utilities Co. Division	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
11/95 12/95	U-21485 (Supplemental Direct) U-21485 (Surrebuttal)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.

Expert Testimony Appearances
of
Lane Kollen
As of January 2005

Date	Case	Jurisdict.	Party	Utility	Subject
1/96	95-299-EL-AIR 95-300-EL-AIR	OH	Industrial Energy Consumers	The Toledo Edison Co. The Cleveland Electric Illuminating Co.	Competition, asset writeoffs and revaluation, O&M expense, other revenue requirement issues.
2/96	PUC No. 14967	TX	Office of Public Utility Counsel	Central Power & Light	Nuclear decommissioning.
5/96	95-485-LCS	NM	City of Las Cruces	El Paso Electric Co.	Stranded cost recovery, municipalization.
7/96	8725	MD	The Maryland Industrial Group and Redland Genstar, Inc.	Baltimore Gas & Electric Co., Potomac Electric Power Co. and Constellation Energy Corp.	Merger savings, tracking mechanism, earnings sharing plan, revenue requirement issues.
9/96 11/96	U-22092 U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues, allocation of regulated/nonregulated costs.
10/96	96-327	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental surcharge recoverable costs.
2/97	R-00973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Stranded cost recovery, regulatory assets and liabilities, intangible transition charge, revenue requirements.
3/97	96-489	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental surcharge recoverable costs, system agreements, allowance inventory, jurisdictional allocation.
6/97	TO-97-397	MO	MCI Telecommunications Corp., Inc., MCImetro Access Transmission Services, Inc.	Southwestern Bell Telephone Co.	Price cap regulation, revenue requirements, rate of return.

Expert Testimony Appearances
of
Lane Kollen
As of January 2005

Date	Case	Jurisdict.	Party	Utility	Subject
6/97	R-00973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	R-00973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Depreciation rates and methodologies, River Bend phase-in plan.
8/97	97-300	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. and Kentucky Utilities Co.	Merger policy, cost savings, surcredit sharing mechanism, revenue requirements, rate of return.
8/97	R-00973954 (Surrebuttal)	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness
10/97	R-974008	PA	Metropolitan Edison Industrial Users Group	Metropolitan Edison Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
10/97	R-974009	PA	Penelec Industrial Customer Alliance	Pennsylvania Electric Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
11/97	97-204 (Rebuttal)	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness of rates, cost allocation.

Expert Testimony Appearances
of
Lane Kollen
As of January 2005

Date	Case	Jurisdict.	Party	Utility	Subject
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
11/97	R-00973953 (Surrebuttal)	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
11/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements, securitization.
11/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
12/97	R-973981 (Surrebuttal)	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements.
12/97	R-974104 (Surrebuttal)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
1/98	U-22491 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
2/98	8774	MD	Westvaco	Potomac Edison Co.	Merger of Duquesne, AE, customer safeguards, savings sharing.

Expert Testimony Appearances
of
Lane Kollen
As of January 2005

Date	Case	Jurisdict.	Party	Utility	Subject
3/98	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	8390-U	GA	Georgia Natural Gas Group, Georgia Textile Manufacturers Assoc.	Atlanta Gas Light Co.	Restructuring, unbundling, stranded costs, incentive regulation, revenue requirements.
3/98	U-22092 (Allocated Stranded Cost Issues) (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
10/98	9355-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Affiliate transactions.
10/98	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, other revenue requirement issues.
11/98	U-23327	LA	Louisiana Public Service Commission Staff	SWEPCO, CSW and AEP	Merger policy, savings sharing mechanism, affiliate transaction conditions.
12/98	U-23358 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
12/98	98-577	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
1/99	98-10-07	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, investment tax credits, accumulated deferred income taxes, excess deferred income taxes.

Expert Testimony Appearances of Lane Kollen As of January 2005

Date	Case	Jurisdict.	Party	Utility	Subject
3/99	U-23358 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
3/99	98-474	KY	Kentucky Industrial Utility Customers	Louisville Gas and Electric Co.	Revenue requirements, alternative forms of regulation.
3/99	98-426	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements, alternative forms of regulation.
3/99	99-082	KY	Kentucky Industrial Utility Customers	Louisville Gas and Electric Co.	Revenue requirements.
3/99	99-083	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements.
4/99	U-23358 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
4/99	99-03-04	CT	Connecticut Industrial Energy Consumers mechanisms.	United Illuminating Co.	Regulatory assets and liabilities, stranded costs, recovery
4/99	99-02-05	CT	Connecticut Industrial Utility Customers mechanisms.	Connecticut Light and Power Co.	Regulatory assets and liabilities stranded costs, recovery
5/99	98-426 99-082 (Additional Direct)	KY	Kentucky Industrial Utility Customers	Louisville Gas and Electric Co.	Revenue requirements.
5/99	98-474 99-083 (Additional Direct)	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements.
5/99	98-426 98-474 (Response to Amended Applications)	KY	Kentucky Industrial Utility Customers Kentucky Utilities Co.	Louisville Gas and Electric Co. and	Alternative regulation.
6/99	97-596	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Request for accounting order regarding electric industry restructuring costs.

Expert Testimony Appearances of Lane Kollen As of January 2005

Date	Case	Jurisdict.	Party	Utility	Subject
6/99	U-23358	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Affiliate transactions, cost allocations.
7/99	99-03-35	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, regulatory assets, tax effects of asset divestiture.
7/99	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co., Central and South West Corp, and American Electric Power Co.	Merger Settlement Stipulation.
7/99	97-596 (Surrebuttal)	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
7/99	98-0452-E-GI	WVa	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
8/99	98-577 (Surrebuttal)	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
8/99	98-426 99-082 (Rebuttal)	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements.
8/99	98-474 98-083 (Rebuttal)	KY	Kentucky Industrial Utility Customers	Louisville Gas and Electric Co. and Kentucky Utilities Co.	Alternative forms of regulation.
8/99	98-0452-E-GI (Rebuttal)	WVa	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.

Expert Testimony Appearances
of
Lane Kollen
As of January 2005

Date	Case	Jurisdict.	Party	Utility	Subject
10/99	U-24182 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
11/99	21527	TX	Dallas-Ft.Worth Hospital Council and Coalition of Independent Colleges and Universities	TXU Electric	Restructuring, stranded costs, taxes, securitization.
11/99	U-23358 Surrebuttal Affiliate Transactions Review	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Service company affiliate transaction costs.
04/00	99-1212-EL-ETPOH 99-1213-EL-ATA 99-1214-EL-AAM		Greater Cleveland Growth Association	First Energy (Cleveland Electric Illuminating, Toledo Edison)	Historical review, stranded costs, regulatory assets, liabilities.
01/00	U-24182 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
05/00	2000-107	KY	Kentucky Industrial Utility Customers	Kentucky Power Co.	ECR surcharge roll-in to base rates.
05/00	U-24182 (Supplemental Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate expense proforma adjustments.
05/00	A-110550F0147	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Merger between PECO and Unicom.
07/00	22344	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	Statewide Generic Proceeding	Escalation of O&M expenses for unbundled T&D revenue requirements in projected test year.
05/00	99-1658-EL-ETP	OH	AK Steel Corp.	Cincinnati Gas & Electric Co.	Regulatory transition costs, including regulatory assets and liabilities, SFAS 109, ADIT, EDIT, ITC.
07/00	U-21453	LA	Louisiana Public Service Commission	SWEPCO	Stranded costs, regulatory assets and liabilities.

Expert Testimony Appearances
of
Lane Kollen
As of January 2005

Date	Case	Jurisdict.	Party	Utility	Subject
08/00	U-24064	LA	Louisiana Public Service Commission Staff	CLECO	Affiliate transaction pricing ratemaking principles, subsidization of nonregulated affiliates, ratemaking adjustments.
10/00	PUC 22350 SOAH 473-00-1015	TX	The Dallas-Ft. Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU Electric Co.	Restructuring, T&D revenue requirements, mitigation, regulatory assets and liabilities.
10/00	R-00974104 (Affidavit)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, capital costs, switchback costs, and excess pension funding.
11/00	P-00001837 R-00974008 P-00001838 R-00974009		Metropolitan Edison Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, regulatory assets and liabilities, transaction costs.
12/00	U-21453, U-20925, U-22092 (Subdocket C) (Surrebuttal)	LA	Louisiana Public Service Commission Staff f	SWEPCO	Stranded costs, regulatory assets.
01/01	U-24993 (Direct)		Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
01/01	U-21453, U-20925 and U-22092 (Subdocket B) (Surrebuttal)		Louisiana Public Service Commission Staff	Entergy Gulf States, Inc,.	Industry restructuring, business separation plan, organization structure, hold harmless conditions, financing.
01/01	Case No. 2000-386	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Recovery of environmental costs, surcharge mechanism.
01/01	Case No. 2000-439	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Recovery of environmental costs, surcharge mechanism.

Expert Testimony Appearances
of
Lane Kollen
As of January 2005

Date	Case	Jurisdict.	Party	Utility	Subject
02/01	A-110300F0095 A-110400F0040	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance	GPU, Inc. FirstEnergy	Merger, savings, reliability.
03/01	P-00001860 P-00001861	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co. and Pennsylvania Electric Co.	Recovery of costs due to provider of last resort obligation.
04 /01	U-21453, U-20925, U-22092 (Subdocket B) Settlement Term Sheet	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on overall plan structure.
04 /01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
05 /01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues Transmission and Distribution (Rebuttal)	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, Separations methodology.
07/01	U-21453, U-20925, U-22092 (Subdocket B) Transmission and Distribution Term Sheet	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on T&D issues, agreements necessary to implement T&D separations, hold harmless conditions, separations methodology.
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Review requirements, Rate Plan, fuel clause recovery.
11/01 (Direct)	14311-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.

Expert Testimony Appearances
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Lane Kollen
As of January 2005

Date	Case	Jurisdict.	Party	Utility	Subject
11/01 (Direct)	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, capital structure, allocation of regulated and nonregulated costs, River Bend uprate.
02/02	25230	TX	Dallas Ft.-Worth Hospital Council & the Coalition of Independent Colleges & Universities	TXU Electric	Stipulation. Regulatory assets, securitization financing.
02/02 (Surrebuttal)	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
03/02 (Rebuttal)	14311-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, earnings sharing plan, service quality standards.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Revenue requirements. Nuclear llife extension, storm damage accruals and reserve, capital structure, O&M expense.
04/02 (Supplemental Surrebuttal)	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
04/02	U-21453, U-20925 and U-22092 (Subdocket C)		Louisiana Public Service Commission Staff	SWEPCO	Business separation plan, T&D Term Sheet, separations methodologies, hold harmless conditions.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and The Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
08/02	U-25888	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc. and Entergy Louisiana, Inc.	System Agreement, production cost disparities, prudence.
09/02	2002-00224 2002-00225	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Line losses and fuel clause recovery associated with off-system sales.
11/02	2002-00146 2002-00147	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Environmental compliance costs and surcharge recovery.
01/03	2002-00169	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Power Co.	Environmental compliance costs and surcharge recovery.

Expert Testimony Appearances
of
Lane Kollen
As of January 2005

Date	Case	Jurisdict.	Party	Utility	Subject
04/03	2002-00429 2002-00430	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Extension of merger surcredit, flaws in Companies' studies.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, Capital structure, post test year Adjustments.
06/03	EL01-88-000 Rebuttal	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
06/03	2003-00068	KU	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Environmental cost recovery, correction of base rate error.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Unit power purchases and sale cost-based tariff pursuant to System Agreement.
11/03	ER03-583-000, ER03-583-001, and ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001, and ER03-682-002 ER03-744-000, ER03-744-001 (Consolidated	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Market-Ing, L.P, and Entergy Power, Inc.	Unit power purchase and sale agreements, contractual provisions, projected costs, levelized rates, and formula rates.
12/03	U-26527 Surrebuttal	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, Capital structure, post test year Adjustments.
12/03	2003-0334 2003-0335	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Earnings Sharing Mechanism.
12/03	U-27136	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc.	Purchased power contracts between affiliates, terms and conditions.
03/04	U-26527 Supplemental Surrebuttal	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post test year

Expert Testimony Appearances
of
Lane Kollen
As of January 2005

Date	Case	Jurisdict.	Party	Utility	Subject
					Adjustments.
03/04	2003-00433	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	SOAH Docket 473-04-2459, PUC Docket 29206	TX	Cities Served by Texas-New Mexico Power Co.	Texas-New Mexico Power Co.	Stranded costs true-up, including including valuation issues, ITC, ADIT, excess earnings.
05/04	04-169-EL-	OH	Ohio Energy Group, Inc.	Columbus Southern Power Co. & Ohio Power Co.	Rate stabilization plan, deferrals, T&D rate increases, earnings.
06/04	SOAH Docket 473-04-4555 PUC Docket 29526	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Stranded costs true-up, including valuation issues, ITC, EDIT, excess mitigation credits, capacity auction true-up revenues, interest.
08/04	SOAH Docket 473-04-4556 PUC Docket 29526 (Suppl Direct)	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Interest on stranded cost pursuant to Texas Supreme Court remand.
09/04	Docket No. U-23327 Subdocket B	LA	Louisiana Public Service Commission	SWEPCO	Fuel and purchased power expenses recoverable through fuel adjustment clause, trading activities, compliance with terms of various LPSC Orders.
10/04	Docket No. U-23327 Subdocket A	LA	Louisiana Public Service Commission	SWEPCO	Revenue requirements.

Expert Testimony Appearances
of
Lane Kollen
As of January 2005

Date	Case	Jurisdict.	Party	Utility	Subject
12/04	Case No. 2004-00321 Case No. 2004-00372	KY	Gallatin Steel Co.	East Kentucky Power Cooperative, Inc., Big Sandy Recc, etal.	Environmental cost recovery, qualified costs, TIER requirements, cost allocation.

EXHIBIT___(LK-2)

Affiliate Audit Report

Please see attached a copy of the Affiliate Audit Report with Appendices.

EXHIBIT___(LK-3)

Atlanta Gas Light Company
Docket No. 18638-U
GPSC Staff-4

Data Request: GPSC Staff-4

Question: STF-4-16

Please provide the amount of AGLSCo allocated interest to AGLC for each month in the projected test year.

Response:

Interest costs were not allocated from AGLSCo to AGLC for the projected test year due to the inclusion of the allocable portion of AGSC assets in AGLC's rate base.

This response was prepared by or under the supervision of Mike Morley, Director, Financial Accounting, AGL Services Company.

Atlanta Gas Light Company
Docket No. 18638-U
GPSC Staff-Supplemental 4

__Data Request__: **GPSC Staff-Supplemental 4**

Question: STF-S4-16

Please provide the amount of AGLSCo allocated interest to AGLC for each month in the projected test year. Staff requested the amount of AGLSC allocated interest for each month of the projected test year.

AGLC failed to provide the information requested. Instead, it referred to its treatment in the filing of including the AGLSC plant as if it were AGLC plant, to which it applied the requested AGLC's rate of return—which is not what was requested. AGLSC plant is included on AGLSC's books, not AGLC's and AGLSC incurs interest only, not AGLC's overall rate of return. That interest is allocated to AGLC and the other AGLR affiliates.

Response:

The Company did not estimate interest expense for AGLSCo for the projected test year. Therefore, the Company did not calculate interest costs allocated from AGLSCo to AGLC in the projected test year. In summary, the Company does not have the information requested.

This response was prepared by or under the supervision of Mike Morley, Director, Financial Accounting, AGL Services Company.

EXHIBIT___(LK-4)

STAFF CASH WORKING CAPITAL ADJUSTMENT ($000)
TEST YEAR ENDING NOVEMBER 30, 2005

Description	Amount As Filed	Staff Adjustments	Adjusted Amount	Lag	Dollar Days
Revenues	446,060	(18,197)	427,863	7.14	3,054,942
Damaged Billing Revenues	2,391		2,391	30.21	72,232
	448,451	(18,197)	430,254	7.27	3,127,174
Salaries and wages	40,034		40,034	12.00	480,409
Uncollectible accounts	598		598	75.21	44,976
Pension expense	5,107	(3,299)	1,808	183.02	330,806
Retirement Savings Plus Plan	1,446		1,446	22.89	33,098
Other post retirement benefits (Health Insurance)	2,707	(561)	2,146	7.33	15,728
Health/Life Insurance	4,057		4,057	11.96	48,527
Franchise Fees	13,233		13,233	45.99	608,570
Allocation from service company	106,590	(22,503)	84,087	48.40	4,069,827
Other operating expenses	41,014	(7,167)	33,847	36.51	1,235,647
Operations, Maintenance, Capitalized and Distributed and Allocations	214,786	(33,531)	181,255		6,867,589
Taxes other than income taxes	18,078	(1,056)	17,022	166.26	2,830,031
Current Income Taxes - Federal and State	30,849	7,906	38,755	36.75	1,424,233
Interest on Customer Deposits	49		49	-	
Interest ST Debt	1,937	(480)	1,457	(20.44)	(29,785)
Interest LT Debt	29,662	(3,357)	26,305	91.57	2,408,723
Preferred Dividends	11,744	(211)	11,533	66.65	768,657
Total Operating Expenses	307,105	(30,730)	276,375	(51.63)	14,269,447
Net Lag Days				(44.36)	
Average Daily Operating Expenses					757
Cash Working Capital Required for Operating Expenses					(33,582)
Tax Collections Withheld					(607)
Net Cash Working Capital Provided					(34,189)
Net Cash Working Capital Per AGLC Filing					(39,478)
Adjustment to Rate Base for CWC					5,289

EXHIBIT___(LK-5)

AGLC RATE BASE
TEST YEAR ENDING NOVEMBER 30, 2005 ($000)

Rate Base per AGLC Filing		$1,210,676
Less:	AGLS Net Assets	45,065
	Pension Liability	15,211
	Post Retirement Benefits Liability	4,756
	CWC Adjustments	(5,289)
	Accumulated Depr for Adjusted Depreciation Rates	(5,064)
	ADIT for Adjusted Depreciation Rates	1,959
	Include SNG for Test Year	(34,879)
Net Change in Rate Base Staff Recommendation		($21,759)
Adjusted Rate Base Staff Recommendation		$1,188,917

EXHIBIT___(LK-6)

2003 Analyst/ Investor Conference

Savannah, Georgia

November 17-19, 2003

AGL Resources

Seeking Value…
Every Day

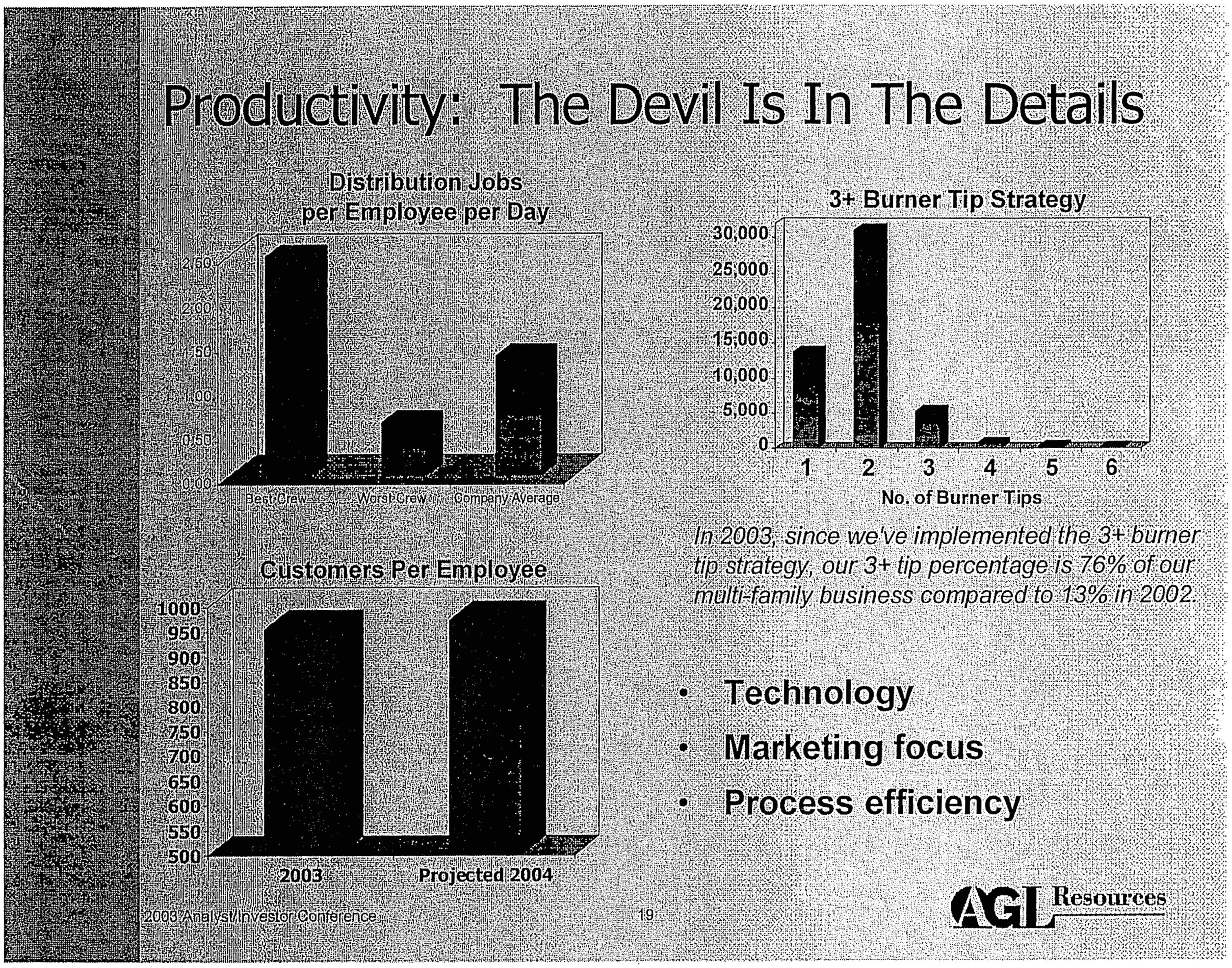
Paula G. Rosput
Chairman, President and Chief Executive Officer

AGL Resources

Current Environment

- Push/pull of costs
- Volatility of product
- Next wave of productivity
- Future deal flow

AGL Resources


Productivity: The Devil Is In The Details
Distribution Jobs per Employee per Day
2.50
2.00
1.50
1.00
0.50
0.00
Best Crew
Worst Crew
Company Average
3+ Burner Tip Strategy
30,000
25,000
20,000
15,000
10,000
5,000
0
1
2
3
4
5
6
No. of Burner Tips
In 2003, since we've implemented the 3+ burner tip strategy, our 3+ tip percentage is 76% of our multi-family business compared to 13% in 2002.
Customers Per Employee
1000
950
900
850
800
750
700
650
600
550
500
2003
Projected 2004
• Technology
• Marketing focus
• Process efficiency
AGL Resources
2003 Analyst/Investor Conference
19

2004 Goals

- We will sustain superior financial and operating performance
- We will reconfigure the gas delivery system to save money for our customers – and invest in our own infrastructure
- We will market our products and services as never before
- We will change our business process and culture by driving technology through everything we do

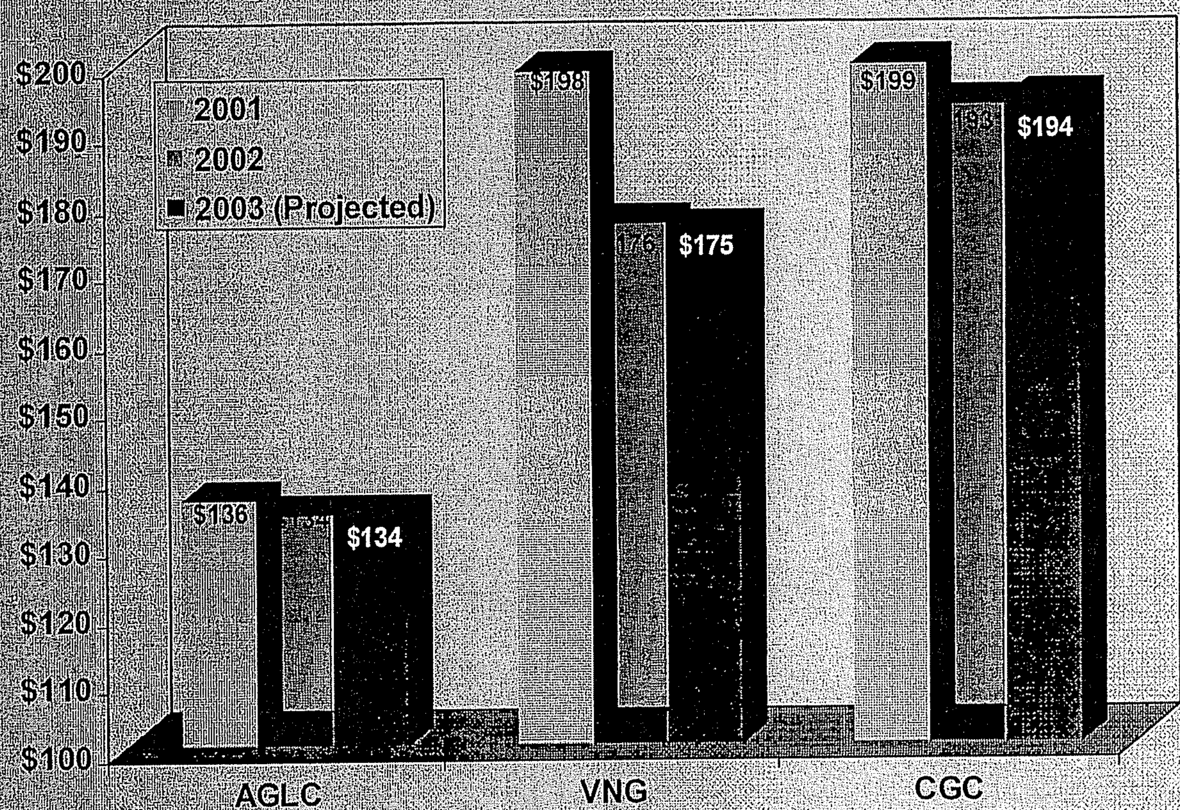
AGL Resources

Distribution Operations: Progress and Possibilities

Kevin P. Madden
Executive Vice President
Distribution and Pipeline Operations

AGL Resources

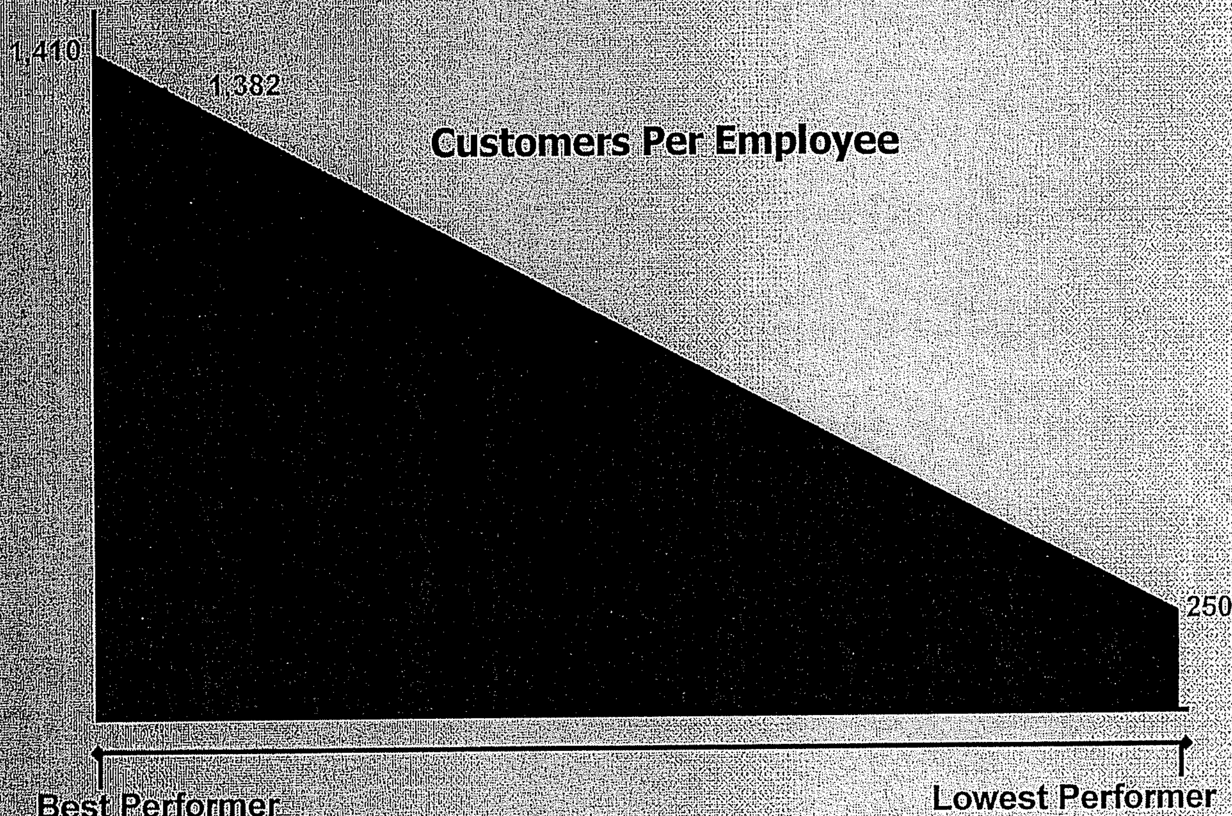
We Also Manage O&M per Customer



AGL Resources

009339

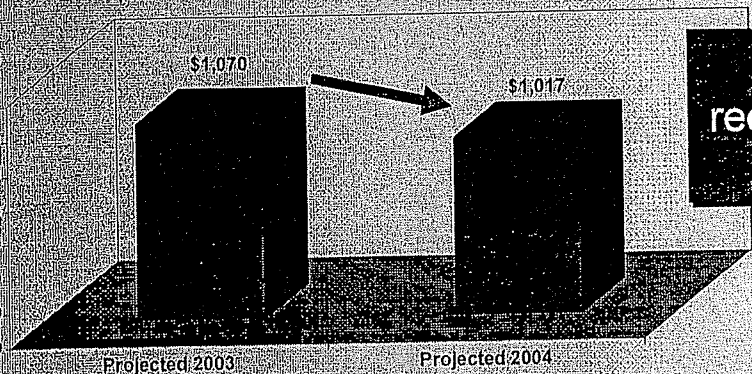
Setting The Standard For Our Peers



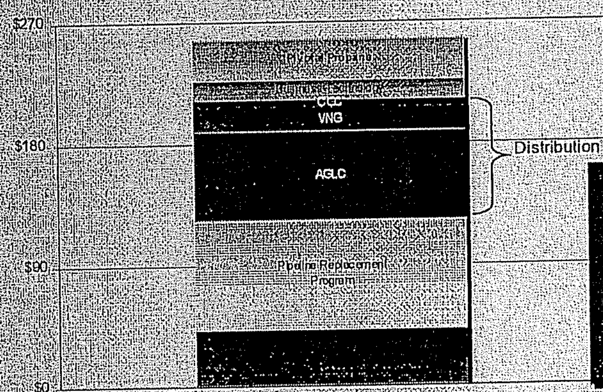
Based on the 2003 American Gas Association Best Practices Benchmarking Survey exclusive of outlying data

AGL Resources

What To Expect In 2004
Lowered Cost per New Meter and Greater Investment in Rate Base



A 5% or greater reduction in cost per new meter

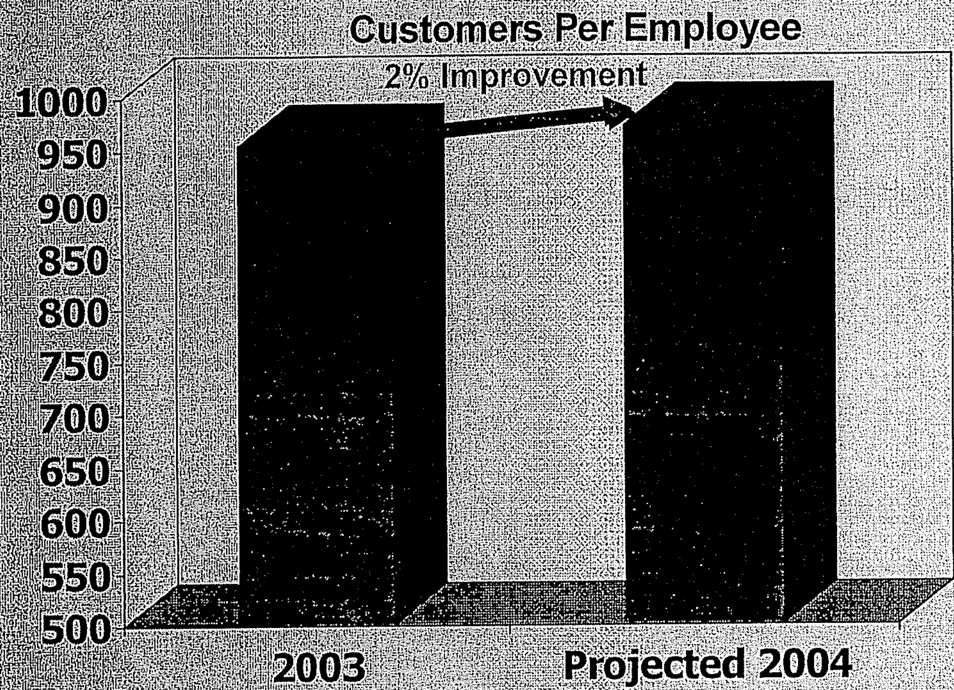


Up to $257 million in projected capital expenditures

AGL Resources

009341

Increased Productivity



Technology initiatives in 2004:
GPS, Marketer Self-Serve, Work Management

AGL Resources

EXHIBIT___(LK-7)

Atlanta Gas Light Company
Docket No. 18638-U
GPSC Staff-4

Data Request: GPSC Staff-4

Question: STF-4-38

With regard to AGL Resources' acquisition of NUI, please provide the following documents:

a) A copy of the prospectus (or other similar document) provided to AGLR stockholders regarding the acquisition.

b) A complete copy of the report provided to AGLR by its financial advisor regarding the efficacy of the purchase and the determination of the valuation of NUI.

Response:

a) The approval of AGL Resources' shareholders was not a required consent for the acquisition of NUI. Consequently, no prospectus (or other similar document) was provided to AGLR stockholders regarding the acquisition. AGL Resources did provide information on the acquisition of NUI to its various stakeholders, including shareholders, through web casts of analyst meetings, press releases, SEC filings and other means. That information is accessible through the company's website.

The approval of NUI Corporation's shareholders was a required consent for the acquisition of NUI by AGL Resources. NUI Corporation did circulate a proxy statement to its shareholders in the process of securing approvals. That proxy statement is available from the SEC website.

This response was prepared by or under the supervision of Richard T. O'Brien, Executive Vice President and Chief Financial Officer of AGL Resources Inc.

b) AGLC objects to this interrogatory because it is not reasonably calculated to lead to the discovery of admissible evidence. Specifically, it seeks documents that do not relate in any way to AGLC's cost of service.

This response was prepared by or under the supervision of Elizabeth Wade, Regulatory Counsel AGL Services Company.

009344

Atlanta Gas Light Company
Docket No. 18638-U
GPSC Staff-Supplemental 4

__Data Request__: **GPSC Staff-Supplemental 4**

Question: STF-S4-38 (b)

With regard to AGL Resources' acquisition of NUI, please provide the following documents:

b) A complete copy of the report provided to AGLR by its financial advisor regarding the efficacy of the purchase and the determination of the valuation of NUI.

Staff requested that AGLC provide a copy of the report provided to AGLR by its financial advisor regarding the efficacy of the NUI purchase and the determination of the value of NUI.

AGLC failed to provide this report by objecting to it.

Response:

AGLC maintains its objection to STF 4-38 (b) on the grounds that it is not reasonably calculated to lead to the discovery of admissible evidence. Specifically, it seeks documents that do not relate in any way to AGLC's cost of service.

This response was prepared by or under the supervision of Elizabeth Wade, Regulatory Counsel, AGL Services Company.

EXHIBIT___(LK-8)

Atlanta Gas Light Company
Docket No. 18638-U
GPSC Staff-4

Data Request: GPSC Staff-4

Question: STF-4-36

Will the direct costs incurred by AGLR and AGLSCo to acquire and integrate NUI be directly assigned to NUI? If not, please explain.

Response:

The costs associated with the acquisition and integration of NUI have been and will continue to be charged to AGL Resources Inc. (parent or holding company) as is required under the Public Utility Holding Company of 1935. Any costs that can be capitalized rather than expensed will be directly assigned to NUI to be applied to NUI's Goodwill.

This response was prepared by or under the supervision of Richard T. O'Brien, Executive Vice President and Chief Financial Officer of AGL Resources Inc.

009347

Atlanta Gas Light Company
Docket No. 18638-U
GPSC Staff-4

Data Request: GPSC Staff-4

Question: STF-4-37

Please explain how the Company proposes to identify and quantify the costs incurred by AGLSCo related to the NUI acquisition and integration to ensure that they are not charged to AGLC?

Response:

Project cost tracking codes have been established for all costs (expense and capital), including employee time and labor, outside services, travel, etc., related to the NUI acquisition and integration projects. All activities and costs related to NUI are coded with the appropriate project cost tracking code and those costs are directly allocated or assigned to AGL Resources Inc. (parent or holding company) in accordance with the Public Utility Holding Company Act of 1935. For further discussion of the accounting for these costs, refer to Atlanta Gas Light Company's response to STF-4-36.

This response was prepared by or under the supervision of Richard T. O'Brien, Executive Vice President and Chief Financial Officer of AGL Resources Inc.

009348

EXHIBIT___(LK-9)

AGLC OPERATING INCOME
TEST YEAR ENDING NOVEMBER 30, 2005 ($000)

Operating Income per AGLC Filing		$92,637
Add:	Increase Test Year Revenues	$7,436
	Modify Proposed Depreciation Rates	$8,849
	Reduce Depreciation for Lower Actual Plant in Service	$1,278
	Reduce Lease Expense for Amort Caroline St Sale Gain	$2,683
	Correct AGLS Composite Ratio Cost Allocations	$2,955
	Reduce Incentive Compensation Allocation	$2,285
	Reduce Outside Services Allocation	$755
	Reduce Increase to AGLS New Business Services	$800
	Include AGLS Allocated Interest Expense	($1,308)
	Include AGLS VNG Acquisition Cost Alloc Savings	$5,672
	Include AGLS NUI Acquisition Cost Alloc Savings	$11,344
	Reduce Property Tax Expense	$1,056
	Reduce Pension Exp to Remove Special Adjustment	$1,439
	Modify Pension Expense Assumptions	$1,861
	Reduce OPEB Expense to Test Year Projections	$561
	Reduce Group Insurance Expense to Test Year Projections	$574
	Reduce Other Operating Expenses to Remove Escalation	$2,626
	Remove Utility Locate Costs	$500
	Remove Energy Conservation Programs	$4,000
	Include SNGT for Test Year	($533)
	Income Tax Effect of Staff Adjustments	($22,775)
Net Change in Operating Income Staff Recommendation		$32,058
Adjusted Operating Income Staff Recommendation		$124,695

EXHIBIT___(LK-10)

AGLC COST OF CAPITAL
TEST YEAR ENDING NOVEMBER 30, 2005 ($000)

I. AGLC Cost of Capital Per Filing

	Capitalization Per Books	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Short Term Debt	$69,551	4.14%	3.77%	0.1561%	0.1561%
Long Term Debt	$805,201	47.93%	7.14%	3.4222%	3.4222%
Common Equity	$805,201	47.93%	11.20%	5.3682%	8.7543%
Total Capital	$1,679,953	100.00%		8.9464%	12.3326%

II. AGLC Cost of Capital No Post Test Year Cost of Short Term Debt Adjustment

	AGLC Adjusted Capitalization	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Short Term Debt	$69,551	4.14%	2.96%	0.1225%	0.1225%
Long Term Debt	$805,201	47.93%	7.14%	3.4222%	3.4222%
Common Equity	$805,201	47.93%	11.20%	5.3682%	8.7543%
Total Capital	$1,679,953	100.00%		8.9129%	12.2991%

III. AGLC Cost of Capital, No Post TY Cost of STD Adj, New LTD Issuances at AGL Capital

	Staff Adjusted Capitalization	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Short Term Debt	$69,551	4.14%	2.96%	0.1225%	0.1225%
Long Term Debt	$805,201	47.93%	6.64%	3.1826%	3.1826%
Common Equity	$805,201	47.93%	11.20%	5.3682%	8.7543%
Total Capital	$1,679,953	100.00%		8.6733%	12.0594%

IV. AGLC Cost of Capital, No Post TY Cost of STD Adj, New LTD Issuances at AGL Capital, Incl Staff ROE

	Staff Adjusted Capitalization	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Short Term Debt	$69,551	2.25%	2.96%	0.0666%	0.0666%
Long Term Debt	$805,201	50.75%	6.64%	3.3698%	3.3698%
Common Equity	$805,201	47.00%	9.00%	4.2300%	6.8982%
Total Capital	$1,679,953	100.00%		7.6664%	10.3346%